Marketing strategies for ONGC in a deregulated scenario

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PART – 1 CRUDE OIL

List of abbreviations & symbols

AEC	Ahmedabad Electricity Company Ltd.
ALNG	Australia LNG Ltd.
AMIG	Al Manhal International Group
APEX	Accelerated program of exploration
APM	Administered Pricing Mechanism
ARA	Amsterdam Rotterdam Antwerp
ATF	Aviation Turbine Fuel
BBL	Barrel
BCM	Billion cubic metre
BOOT	Built Own Operate Transfer
BP	British Petroleum Ltd.
BPCL	Bharat Petroleum Corporation Ltd.
Bpkm	Billion kilometres
BRPL	Bongaingaon Refineries & Petrochemicals Ltd.
BS&W	Bottom Sediments & Water
Btkm	Billion-tonne kilometres
CBM	Coal Bed Methane
CBU	Cauvery Business Unit
CCEA	Cabinet Committee on Economic Approvals
CEA	Central Electricity Authority
CFCL	Chambal Fertilisers & Chemicals Ltd.
CIF	Cost Insurance Freight
CIL	Coal India Ltd.
CNG	Compressed Natural Gas
CPCB	Central Pollution Control Board
CPCL	Chennai Petroleum Corporation Ltd.
CRF	Capital Recovery Factor
CTF	Central Tank Farm
DGH	Directorate General of Hydrocarbons
DPC	Dabhol Power Corporation Ltd.
DWT	Dead Weight Tonnage
E&P	Exploration and production
EEZ	Exclusive Economic Zone
EIA	Energy Information Administration
EOR	Enhanced Oil Recovery

EPS	Electric Power Survey
ESC	Empowered Standing Committee
FACTS	Fesharaki Associates Consulting & Technical Services Limited
FIPB	Foreign Investment Promotion Board
FO	Fuel oil
FOB	Free on Board
FSU	Former Soviet Union
GAIL	Gas Authority of India Ltd.
GCV	Gross calorific value
GLL	Gopalpur LNG Ltd.
GMB	Gujarat Maritime Board
GOI	Government of India
GPEL	Gujarat PowerGen Energy Corporation Ltd.
GPLNG	Gujarat Pipavav LNG Limited
GPPL	Gujarat Pipavav Port Ltd.
GREP	Gujarat Rehabilitation and Expansion Project
GSEG	Gujarat State Energy General
GSFC	Gujarat State Fertilisers & Chemicals Ltd.
GSPL	Gujarat State Petronet Ltd.
HBJ	Hazira-Bijaipur-Jagdishpur gas pipeline
HLPL	Hazira LNG Private Ltd.
HPCL	Hindustan Petroleum Corporation Ltd.
HPPL	Hazira Port Private Ltd.
HSD	High Speed Diesel
HT	High Tension
HSFO	High Sulphur Fuel Oil
IDC	Interest during the construction period
IEO	International Energy Outlook
IFFCO	Indian Farmers Fertilisers Co-operative
IGFCC	Indo Gulf Fertilisers & Chemicals Corp.
IGL	Indraprastha Gas Ltd.
IOC	Indian Oil Corporation Ltd.
IOR	Improved Oil Recovery
IPE	International Petroleum Exchange
IPPs	Independent power producers
IPR	Industrial Performance Review
JCC	Japanese Crude Cocktail
KEL	Kribhco Energy Ltd.

KG	Krishna-Godavari
KIOCL	Kakinada Indian Oil LNG consortium Ltd.
KRIBHCO	Krishak Bharti Co-operative
KRL	Kochi Refineries Ltd.
KSIDC	Kerala State Industrial Development Corporation Ltd.
KSIIDC	Karnataka State Industrial & Infrastructural Development Corpora
KWh	Kilowatt hour
LC	Letter of Credit
LNG	Liquefied natural gas
LPG	Liquefied Petroleum Gas
LR	Long Range
LSHS	Low Sulphur Heavy Stock
MGL	Mahanagar Gas Ltd.
MMBtu	Million British Thermal Unit
MMCM	Million cubic metres
MMCMD	Million standard cubic metres per day
MMT	Million metric tonnes
MMTPA	Million metric tonnes per annum
MNCs	Multinational Corporations
MoEF	Ministry of Environment and Forests
MoP&NG	Ministry of Petroleum & Natural Gas
MoST	Ministry of Surface Transport
MoU	Memorandum of Understanding
MR	Medium Range
MS	Motor Spirit
MSEB	Maharashtra State Electricity Board
Mtoe	Million tonnes oil equivalent
MW	Mega watt
NCDC	National Coal Development Corporation
NELP	New exploration and licensing policy
NFL	National Fertilisers Ltd.
NHPC	National Hydro Power Corporation
NIOC	National Iranian Oil Company Ltd.
NOCs	National oil companies
NRL	Numaligarh Refineries Ltd.
NSSO	National Sample Survey Organisation
NTPC	National Thermal Power Corporation Ltd.
NYMEX	New York Mercantile Exchange

O&M	Operation & maintenance
OCC	Oil Coordination Committee
OCF	Oswal Chemicals & Fertilisers Ltd.
OEB	Oil Economy Budget
OECD	Organisation for Economic Co-operation & Development
OIL	Oil India Ltd.
OMC	Oil Marketing Company
ONGC	Oil and Natural Gas Corporation Ltd.
OOC	Oman Oil Company
OPEC	Organization of Petroleum Exporting Countries
OSP	Official Selling Price
OVL	ONGC Videsh Ltd.
PFBC	Pressurised fluidised bed combustion
PFC	Power Finance Corporation
PGCIL	Power Grid Corporation of India Ltd.
PIL	Public interest litigation
PLF	Plant load factor
PLL	Petronet LNG Ltd.
PPA	Power purchase agreement
PS	Pulverised coal subcritical power plant
PSCs	Production sharing contracts
PSM	Payment security mechanism
PSU	Public Sector Unit
PTC	Power Trading Corporation Ltd.
R/P	Reserves to production
RCF	Rashtriya Chemicals and Fertilisers Ltd.
RET	Renewable energy technologies
RPS	Retention pricing system
SBM	Single Buoy Mooring
SCCL	Singareni Coal Company
SCI	Shipping Corporation of India
SEB	State Electricity Board
SERC	State Electricity Regulatory Authority
SKO	Superior Kerosene Oil
SMPL	Salaya Mathura Pipeline
SPCB	State Pollution Control Board
SPM	Suspended particulate matter
T&D	Transmission & distribution

TAIPP	Tariff Adjusted Import Parity Price
TCF	Trillion cubic feet
TCL	Tata Chemicals Ltd.
TEC	Tata Electric Company Ltd.
TGPI	Total Gas and Power India Ltd.
TMT	Thousand Metric Tonnes
TNEB	Tamil Nadu Electricity Board
TNLPC	TN LNG & Power Company Private Limited
TPA	Tonnes per annum
TPC	Tata Power Company Ltd.
TPD	Tonnes per day
UAE	United Arab Emirates
ULCC	Ultra Large Crude Carrier
ULSD	Ultra Low Sulphur Diesel
UPSIDC	UP State Industrial Development Corporation Ltd.
USA	United States of America
USD	United States Dollars
VLCC	Very Large Crude Carrier
WS	World Scale
WTI	West Texas Intermediate
WTO	World Trade Organization

Executive summary

This study was undertaken at the instance of ONGCL to evaluate the marketing and pricing options for crude oil, natural gas and value added products – LPG and naphtha, in the deregulated scenario.

PART 1 CRUDE OIL

Global oil scenario

- Over the past decade, the developed regions like North America and Europe have shown a lower growth rate of energy consumption than the developing regions. The fastest growing region was Middle East followed by Asia-Pacific with growth rates of about 16% and 14% respectively.
- According to International Energy Outlook 2002 (IEO 2002), the Asia-Pacific region is expected to increase its share in the total world primary energy consumption to 29% in the year 2010 from the present 27.5 %(figure for the year 2001).
- The share of oil in energy consumption in Asia-Pacific is likely to remain largely unchanged at the level of 40% by 2010 as per the IEO 2002. With growing primary energy demand, this indicates higher oil consumption in the region.
- The oil production capacity is projected to increase to 87.9 million bbls per day by 2005 and to 97.4 million bbls per day by 2010, which indicates an annual growth rate of 4%. Consumption is projected to grow from 84.9 million bbls per day by 2005 to 94.9 million bbls per day by 2010.
- Middle East countries account for 65% of the total world proven oil reserves and for 31% of the total world oil production. Saudi Arabia has the largest oil production while United States of America is the largest consumer of oil/oil products. However, past few months have also seen the emergence of Russia as an important supplier.
- Middle East region accounts for 45% of all the crude oil traded in the world followed by Africa. And given the huge surplus projected in this region, it is

expected that this region will continue to play an important role in global oil trade.

International markets for ONGC crudes

- All ONGC crudes are sweet but they differ in gravity and other physical and chemical properties. Responses from ONGC and from refineries have yielded the following comparable international crudes for the ONGC crudes.

Table 1 Benchmark crudes for ONGC crudes

ONGC crude	Benchmark crude (share in the mix) (Country of origin)
Bombay High	Bonny Light (50%) (Nigeria) Escravos (50%) (Nigeria)
Cauvery Basin	Arab Light (Saudi Arabia)
Krishna Godavan Basin	Arab Light (Saudi Arabia)
South Gujarat	Bonny Light (Nigeria)
North Gujarat	Bonny Light (Nigeria)
Jorhat Assam	Bonny Light (Nigeria)
Moran Assam	Bonny Light (Nigeria)

- The following table shows the demand supply deficit (-)/surplus (+) for all the regions as projected by the IEO 2002.

Table 2 Net Surplus(+)/Deficit (-) (million tonnes)

Regions	1995	2000	2005	2010
North America	-309	-413	-473	-573
Europe	-412	-424	-428	-453
Middle East	777	903	1125	1295
South and Central America	100	130	154	149
Africa	237	257	324	378
Former Soviet Union	141	221	234	314
Asia-Pacific	-501	-588	-861	-1061
World	34	86	75	50

Source. International Energy Outlook, 2002

- The likely demand for imported sweet crude for major consuming regions is as follows.

Table 3 Likely demand for imported sweet crude (million tonnes)

Regions	2005	2010
North America	168	204
Europe	233	246
Asia-Pacific	117	144
Africa	13	15
South and Central America	21	25
Total	552	635

Source. International Energy Outlook, 2002

Note. While arriving at these figures, it has been assumed that the share of sweet crude in total crude imports by surplus regions will remain nearly at the present level and that the share of imported sweet crude in total crude requirement will remain at nearly the present level.

- The exportable surplus of sweet crude from Africa and Former Soviet Union is as follows.

Table 4 Exportable surplus of sweet crude (million tonnes)

Regions	2005	2010
Africa	324	378
Former Soviet Union	234	314
Total	558	692

Source. International Energy Outlook, 2002

- The resulting demand supply situation of sweet crude for the world as a whole is as follows.

Table 5 Demand-supply outlook for sweet crude (million tonnes)

	2005	2010
Demand	552	635
Supply	558	692
Net Surplus[a]	6	58

Source. Own calculations from International Energy Outlook, 2002

- As shown in Table 3, North America is likely to have a huge demand for sweet crude in the coming decade but most of this is likely to be met by West Africa, which is expected to have surplus crude supplies. This also holds true for Europe due to its proximity to African as well as FSU crudes. Hence, if ONGC were allowed to export its crude oil, the likely market would be restricted to Asia-Pacific.
- However, although ONGC could theoretically explore the markets in South Asia, the current domestic legislation does not permit it to export and this situation is not likely to change in the near future.

Oil use pattern by Indian refineries

- The Hydrocarbon Vision 2025 (HC Vision) projects India's requirement of petroleum products to be about 370 MMTPA in 2025 and projects domestic crude production in 2025 to be about 60 million tonnes. Thus, crude imports to India in 2025 can be estimated to be about 310 MMT. This implies that share of imports in total oil requirement will rise from about 70% at present to about 84% in 2025.

[a] See the main report for further remarks

- Historically most of the crude imports are sourced from the Middle East region. The next largest exporter to India is Africa, especially Nigeria, followed by Malaysia.
- Among imported crudes, in 2000-01, the percentage of low sulphur and high sulphur crudes were 26% and 74% respectively. In the total crude usage by refineries (domestic production plus imports), the percentage of low and high sulphur was 47% and 53% respectively.
- The maximum capacity addition since 1975 has been in the last 5 years to the extent of 54 MMT. Thus the Xth Plan targets of capacity addition of 106 MMTPA seems a bit ambitious. However, in view of the surplus situation emerging in some petro-products, the Xth Plan also provides a base case estimate of crude imports, considering materialisation of 70% of projected refinery capacity additions and 90% utilisation of capacity.
- The processing requirements and the gross import requirements as projected by the Xth plan – the high and base case scenarios is provided in Table below.

Table 6 Crude oil processing and imports (MMT) during Xth Plan

	2002-03	2003-04	2004-05	2005-06	2006-07
High Case					
Total processing need	127.672	154.906	174.081	181.392	213.806
Indigenous	29.336	30.646	31.782	31.88	31.558
Imported	98.336	124.26	142.299	149.512	182.248
Gross imports	98.83	124.884	143.014	150.264	183.163
Base Case					
Total processing need	117.572	142.247	146.447	173.047	177.457
Indigenous	29.336	30.646	31.782	31.88	31.558
Imported	88.236	111.601	114.665	141.167	145 899
Gross imports	88.679	112.162	115.241	141.876	146.632

Source. Tenth plan sub-group report on marketing

- Thus the Xth Plan projections imply increasing share of imported crude oils in total oil needs as refinery capacity is projected to increase substantially and domestic crude production to remain more or less stagnant.
- The Xth Plan projects high and base case scenarios of the quantity of high and low sulphur crude oils to be imported in future based on the crude mix as indicated by refineries. This is tabulated in table 7 below.

Table 7 Share of high and low sulphur oils in total crude requirements (million tonnes)

	2002-03	2003-04	2004-05	2005-06	2006-07
High case					
Total processing need	127.672	154.906	174.081	181.392	213.806
Indigenous	29.336	30.646	31.782	31.88	31.558
Imported	98.336	124.26	142.299	149.512	182.248
High sulphur	70.499	87.375	102.023	107.617	142.774
Low sulphur	27.837	36.885	40.276	41.895	39.474
HS %	55	56	59	59	67
LS %	45	44	41	41	33
Gross imports	98.83	124.884	143.014	150.264	183.163
High sulphur	70.853	87.814	102.536	108.158	143.491
Low sulphur	27.977	37.07	40.478	42.106	39.672
HS %	72	70	72	72	78
LS %	28	30	28	28	22
Base case					
Total processing need	117.572	142.247	146.447	173.047	177.457
Indigenous	29.336	30.646	31.782	31.88	31.558
Imported	88.236	111.601	114.665	141.167	145.899
High sulphur	64.922	80.235	85.828	102.666	118.501
Low sulphur	23.314	31.366	28.837	38.501	27.398
HS %	55	56	59	59	67
LS %	45	44	41	41	33
Gross imports	88.679	112.162	115.241	141.876	146.632
High sulphur	65.248	80.638	86.259	103.182	119.096
Low sulphur	23.431	31.524	28.982	38.694	27.536
HS %	74	72	75	73	81
LS %	26	28	25	27	19

Source. Tenth plan sub-group report on marketing

Approach towards marketing strategy

- In view of the high import dependency of India for meeting its crude oil requirement, Government of India may not permit ONGC to export its crude oil. Furthermore, due to the unpredictable political climate in Middle East & neighbouring Afghanistan, oil security for the country assumes considerable importance, which gives another reason not to relax the export restriction on indigenous crude.
- A change in policy stance on restricting the ONGC crude to the Indian market is hence not envisaged.
- Therefore though ONGC may be expecting to move towards import parity prices while fixing its price for crude from April '02, it will not be easy for it to convince the refineries for the same. Similarly refinery may not be justified in insisting that they will not pay more than international price, because ONGC will be committed to pay certain liabilities to the Government of India under various rule out of the amount which they get from refineries.
- The proposed pricing strategy is then composed of two components- base price and premiums/discounts.

Base price – This is the basic price of the crude oil linked to the price of comparable international crude. There are two choices as far as linkage with the international crude is concerned. Firstly, it can be linked to the import parity price of the comparable international crude, calculated as on a negotiated location. However, it can be contended by the refineries that since they are buying crude from the Indian fields, they cannot be expected to pay the import parity prices since that will include, *inter alia*, the freight from the loading port of the international crude which will accrue to ONGC for no perceived service.

The another option is taking FOB price of the comparable crude as the base price, taken as on a negotiated location or point of transfer.

However, there is an important difference between the imports and indigenous purchases – the imposition of sales tax. Sales tax is levied on indigenous goods while customs duty is imposed on imported goods. Thus, to bring parity between two transactions, we have considered the payment of sales tax as a negotiable cost for ONGC and refineries.

Premiums/Discounts – Over and above the base price, there will be some premiums or discounts depending on the quality of the crude and the relative competitive position of ONGC vis-à-vis the refineries.

- The various options for base price that have been thus examined are:

  Option A. ONGC receives fob of comparable international crude and pays central sales tax.

  Option B. ONGC receives fob of comparable international crude but does not pay central sales tax.

  Option C. ONGC receives import parity price of comparable international crude and does not pay central sales tax.

  Option D. ONGC receives import parity price of comparable international crude and pays central sales tax.
- The premiums and discounts are evaluated on the following basis-
  - Quality of crude
  - Supply infrastructure to the refineries
  - Alternative options for refineries and ONGC
  - Security concerns attached to the imported crudes
  - Exchange rate risks in imports
  - Infrastructural constraints for refineries in importing more crude oil
- One more factor requires settlement is the custody transfer point since that will determine as to who will bear the cost of transportation of crude to the refinery.

- Netting out all the payments and cost of production of ONGC, which according to ONGC officials averages around $9/bbl, leaves the surplus for ONGC which will be available to meet its investment commitments in exploration and production. This exercise is carried out on the assumption that ONGC would like to remain a zero debt company and hence would finance its exploration commitments from its balance sheet only. This surplus has been calculated field wise.
- This surplus will show the sustainability of each field under different pricing schemes and thus will determine the range of options for ONGC.

Strategy for Bombay High

Existing and potential customers

- The bulk of BH crude (about 11 MMT) is consumed by the refineries at Mumbai (BPCL and HPCL) and Kochi. Given the proximity of these refineries to the BH field, they are expected to continue to procure the BH crude in future too.
- The Reliance refinery at Jamnagar also imports all its crude requirement at present and ONGC has to negotiate with Reliance on same terms as with other customers. However, the average imported crude procurement cost of Reliance in 2000 was about $23/bbl as against an average of $29.60/bbl for the existing customers of BH crude. ONGC has to keep this in mind while considering Reliance as a potential customer for BH crude.
- The Bhatinda and Bina refineries are far moved from the BH fields and also the date of their commissioning is uncertain. Hence these refineries have not been considered in our analysis as potential customers.
- HPCL being the government nominee, through which Ravva crude has to be sold, it is unlikely that Vizag refinery will replace Ravva with BH crude when Ravva will be a cheaper option. However, BH can replace the imported crude from Africa by Vizag, which was 1.84 MMT in 2001.

Evaluation of options

- An evaluation of the four options discussed above shows that the difference between the basic price under Option A (the worst option) and the Option C (the best option) is Rs 1591.92/MT or $ 4.72/bbl. This then represents the margin in negotiations, sharing of which will depend on the negotiating power of the parties involved.

- The comparable international crude identified for the purpose of base price is a mix of Bonny Light and Escravos in equal proportion (Table 1, page ii).

Premium factors for ONGC

Security of supplies

- The premium on this account may be payable due to the fact that imported crudes always carry a risk of non supply due to volatile political climate in the producing countries, in which event the fixed cost per tonne of crude processed will rise. Thus, if a refinery chooses to replace indigenous crude by the imported crude, it is taking that extra risk of disruption in supplies. Thus, a refinery processing the indigenous crude is avoiding that risk to the extent to indigenous crude processing and hence can be expected to pay a premium on this account.
- The increase in fixed costs per tonne in case of crude supply disruptions and lower refining capacity utilisation is shown below.

Table 8 Increase in fixed refining costs

Refinery	Rs/MT	$/bbl
Existing customers		
BPCL	6	0.017
HPCL	3	0.010
Kochi	10	0.031
Chennai	9	0.028
Mathura	4	0.011
Panipat	9	0.028
Koyali	2	0.007
Potential customers		
Mangalore	10	0.029
Vizag	1	0.003

Port facilities augmentation for higher imports

- This takes into account the infrastructural requirements for buying more of imported crudes as against the indigenous crudes. Certain port constraints like available capacity, draft, restrictions on size of vessel etc may inhibit a refinery's plan to buy more imported crude and hence may make it dependent on the ONGC crudes, at least for some proportion of the refinery throughput. If such is the case, the refinery may have the option to extend the port facilities at certain cost, which can be then used as a proxy for quantifying this advantage of the refineries.
- The port at Vadinar, at which imports for Koyali, Mathura and Panipat refineries land, has sufficient capacity to cater to greater imports. Hence

demurrage from these refineries have been considered as nil. However the % occupancy of Pirpau, Cochin and Chennai ports are high and may entail large demurrage costs in case of greater imports. Considering cargoes from Nigeria in October 2000 to May 2001, the average demurrage at West Coast India and East Coast India has been Rs 9.72 /MT and Rs 9.52 /MT, respectively.

Letter of credit charges

- The LOC charge is an indispensable requirement in any international transaction and represents a variable cost that means that it increases with increase in imports.
- The level of LC charges depends on the creditworthiness of the buyer. IOC, being a fortune 500 company, may be paying a lower LC charge while any standalone refinery, importing crude independently for the first time, may be required to pay a higher LC charge. Thus, refineries importing for the first time may be required to pay a higher LC charges, which would then be an extra cost in self-imports as against purchase of indigenous crude. And in so far as the normal import parity principle does not include this extra cost, a separate premium may be charged from the refineries.
- The increase in the cost of crude imports on account of 0.1 percentage point increase in LC charge is shown below.

Table 9 LC Charges

Refinery	Rs/MT	$/bbl
Existing customers		
BPCL/HPCL	7.35	0.021
Kochi	7.32	0.021
Chennai	7.35	0.021
Mathura	-	-
Panipat	-	-
Koyali	-	-
Potential Customers		
Vizag	7.39	0.021
Mangalore	7.33	0.021

Foreign exchange risks

- These risks arise due to the fact that crude imports will be payable in dollars while the indigenous purchase can be paid in rupee. Thus, the final outgo for the refinery is exposed to foreign exchange risk due to volatile nature of foreign exchange markets.
- A 1% depreciation of the rupee will increase the cost of importing from the base case, as shown below.

Table 10 Exchange rate risks

Refinery	Rs/MT	$/bbl
Existing Customers		
BPCL/HPCL	81.66	0.242
Kochi	81.30	0.241
Chennai	81.74	0.242
Mathura	82.14	0.243
Panipat	81.74	0.242
Koyali	81.74	0 242
Potential Customers		
Vizag	82.03	0.243
Mangalore	81.48	0.241

Freight diseconomies

- Presently, the imported crude oil requirements of the coastal refineries like HPCL and BPCL is taken care by IOC, which brings crude at Vadinar in large tankers from where it is distributed domestically. However with deregulation, refineries importing independently may have to import in smaller vessels that will increase freight expenses, unless they continue with the present arrangements with IOC.
- Increase in cost of crude imports on account of importing in LR-II as compared to VLCC for select refineries, is as follows.

Table 11 Freight diseconomies

Refinery	Rs/MT	$/bbl
Existing Customers		
BPCL/HPCL	220.53	0.654
Kochi	210.49	0.624
Chennai	223.32	0.662
Mathura	-	-
Panipat	-	-
Koyali	-	-
Potential Customers		
Vizag	231.01	0.685
Mangalore	215.56	0.639

Discount factors for ONGC

High BS&W in ONGC crudes

- In the deregulated scenario, the refineries paying the price on international parity will demand international quality crude. However, the BS&W of BH crude, at 0.1%, is higher than the international standard of 0.02%, above which the crude is discounted. Thus, BH crude is also likely to be discounted on this account.

- The current sale of BH crude is about 15 MMT. Desalting of this crude would cost around Rs. 1500 million according to estimates provided by ONGC. The annutised capital cost is estimated at 16.47 Rs/MT.

Summary table for Bombay High

Table 12 Summary of premiums and discount

		Existing Customers							Potential Customers	
	Unit	BPCL	HPCL	Chennai	Kochi	Mathura	Panipat	Koyali	Vizag	Mangalore
remium factors for ONGC										
ecurity of supplies	Rs/MT	6	3	9	10	4	9	2	1	10
emurrage charges	Rs/MT	9.72	9.72	9.52	9.72	0	0	0	9.52	9.72
Charges	Rs/MT	7.35	7.35	7.35	7.32	0	0	0	7.39	7.33
xchange rate risks	Rs/MT	81.66	81.66	81.74	81.3	82.14	81.74	81.74	82.03	81.48
reight diseconomies	Rs/MT	220.53	220.53	223.32	209.21	0	0	0	231.01	215.56
otal Premium	Rs/MT	325.26	322.26	330.93	317.55	86.14	90.74	83.74	330.95	324.09
iscount factors for ONGC										
S&W problem	Rs/MT	16.47	16.47	16.47	16.47	16.47	16.47	16.47	16.47	16.47
otal Discount	Rs/MT	16.47	16.47	16.47	16.47	16.47	16.47	16.47	16.47	16.47
verage Net Premium	Rs/MT	308.79	305.79	314.46	301.08	69.67	74.27	67.27	314.48	307.62
verage Net Premium	$/bbl	0.916	0.907	0.933	0.893	0.207	0.220	0.200	0.933	0.912

Strategic option

- Applying this premium to all the four options for basic price for BH crude yields the following surplus for ONGC.

Table 13 Surplus for ONGC ($/bbl)

Refinery	Option A	Option B	Option C	Option D
BPCL - Mumbai	1.86	2.37	5.44	4.81
HPCL - Mumbai	1.86	2.37	5.44	4.82
Koyali	1.40	1.91	4.98	4.34
Mathura	1.40	1.91	4.98	4.35
Panipat	1.41	1.92	4.99	4.36
Kochi	1.85	2.36	5.43	4.80
Vizag	1.88	2.38	5.45	4.82
MRPL	1.86	2.37	5.44	4.81
Chennai	1.88	2.38	5.45	4.82

- Given the ONGC's exploration commitment of $2.3/bbl[b], it seems that ONGC is in the position to negotiate for Option C. However it should accept no less than Option D which means that it should get the import parity price for BH and may pay the sales tax on behalf of the refineries.

[b] As per the Annual Report of ONGC, it plans to invest Rs 47590 million in various EOR/IOR schemes and expects to increase the reserves by 61.53 million tonnes in 20 years. This works out as $2.3/bbl.

Strategy for North and South Gujarat

Existing and potential customers

- To the extent that ONGC has no alternate infrastructure to supply these crudes to any refinery except Koyali, either in India or abroad, ONGC is likely to continue to be dependent on Koyali refinery for Gujarat crudes.
- Reliance's Jamnagar refinery is the only other operating refinery in the region and hence can theoretically take the Gujarat crudes. However, the average procurement cost for Reliance for the year 2000/01 was \$23.18/bbl which is lower than Koyali refinery's \$29.64/bbl.

Evaluation of options

- The difference between Option A and Option C is Rs 1601.56/MT or \$ 4.749/bbl, which then represents the negotiating margin. The comparable international crude identified for the purpose of base price is Bonny Light.
- Among many other things that have to be negotiated between Koyali and ONGC is cost of transporting the crude from Vadinar to respective Central Tank Farms (CTF) in North and South Gujarat. This is because under the import parity option, the prices have been calculated as at Vadinar port. Thus, in the event that the point of transfer between ONGC and Koyali is set at Vadinar, then the costs of moving crude from Vadinar to Koyali will be borne by Koyali. Else, the cost of moving the crude from any intermediate point of transfer to the Koyali refinery shall be negotiated between the parties.

Premium factors for ONGC

Security of supplies

- On the lines similar to those mentioned above, the increase in fixed cost per tonne on account of lower capacity utilisation due to disruption in supplies for Koyali refinery for North and South Gujarat crudes is shown below.

Table 14 Increase in fixed cost

Refinery	Rs/MT	\$/bbl
North Gujarat	3.868	0.011
South Gujarat	3.441	0.010

Augmentation of facilities for higher imports

- The capacity of the Salaya-Mathura Pipeline (SMPL) is completely utilised and cannot support extra volume of 5.5 MMTPA. This means that to replace Gujarat crudes by imported crudes, IOC will have to augment the capacity of SMPL. By thumbrule estimates, it costs around Rs 0.1 million per inch diameter per kilometre to install a crude pipeline. Taking this estimate, it will cost around Rs 745.2 million to set up a new pipeline of 18" from Vadinar to Koyali which would yield an annutised capital cost of Rs 17.17/MT.
- Reliance imports its entire throughput of crude and hence has at its disposal the import infrastructure, which can sustain the current level of imports. Thus, it does not need to augment any import infrastructure. Moreover, Reliance is not dependent on ONGC for its crude requirement. Thus, it will not pay any premium on this account.

Letter of credit charges

- As mentioned above, the letter of credit charges for importing crude vary from buyer to buyer. IOC being a Fortune 500 company and because of the fact that it has been importing crude for many years would not be required to pay an extra LC charge. Hence no premium can be charges from Koyali on this account.

Foreign exchange risks

- A 1% depreciation in rupee will raise the import cost of an equivalent quality crude for Koyali refinery by Rs 81.87/MT ($0.242/bbl). This amount can be asked as a premium for foreign exchange risks.

Freight diseconomies

- The combined requirement of imported crudes by the three IOC refineries in the northwest India (Koyali, Mathura and Panipat) is 16.69 MMTPA. The maximum capacity of a VLCC tanker is 0.3 MMT. Thus, IOC can sustain a vessel size of VLCC for its imported crude requirement and hence cannot be expected to pay a premium on the account of bringing crude on a smaller vessel.

Discount factors for ONGC

High BS&W in Gujarat crudes

- A desalter plant at Kalol is already desalting the North Gujarat crude but additional costs may have to be incurred for the same for South Gujarat crude. According to estimates given by ONGC, it costs around Rs 100 million to desalt 1 MMT of crude which gives an annutised capital cost of Rs 22.3/MT for desalting the 2.3 million tonnes of South Gujarat crude.

No alternative for ONGC

- Even if ONGC were allowed to export the crude, the lack of supporting infrastructure would prevent ONGC from doing so. The only other refinery that can possibly move ONGC crudes is the Reliance's Jamnagar refinery. But there is no infrastructure to move the crude from ONGC's CTFs in North and South Gujarat to the Reliance's refinery either.
- As per the ETG recommendations, the tariff for new crude pipeline comes out to be Rs 1.23/MT/Km[c]. The average distance from Nawagam and Ankleshwar to Jamnagar is 311 and 484 kms respectively. Thus the cost of transportation is estimated as Rs 382.53/MT and Rs 595.32/MT respectively.

Summary table for Gujarat crudes

Table 15 Summary of premiums and discounts for Gujarat crudes

	Rs/MT	$/bbl
Premium factors for ONGC		
Security of supplies		
a) North Gujarat crude	3 86	0 01
b) South Gujarat crude	3 44	0 01
Augmentation of facilities for imports	17 17	0 05
Cost of international procurement		
Exchange rate risks	81 87	0 24
Total		
a) North Gujarat crude	102.90	0 30
b) South Gujarat crude	102.48	0 30
Discount factors for ONGC		
Inferior quality crude		
a) North Gujarat crude*	-	-
b) South Gujarat crude	22 3	0 06
No alternative for ONGC		
a) North Gujarat crude	382.53	1 13
b) South Gujarat crude	595 32	1 76
Total		

[c] The ETG gives the pipeline tariff as Rs 1.13/MT/KM. Escalating it by 80% of the WPI index for each year after 1999-00, we have the tariff as Rs 1.23/MT/KM.

a) North Gujarat crude	382.53	1.13
b) South Gujarat crude	617 62	1.83
Net discount		
a) North Gujarat crude	279.62	0.82
b) South Gujarat crude	515.13	1.52
Average Discount	375 16	1 11

* This does not takes into account that fact that North Gujarat crude is highly acidic and hence ONGC will have to give a discount on this account also which may be negotiated with the refinery

Strategic option

- Applying this discount to all the four options and deducting the various charges ONGC will have to pay, the following surpluses emerge.

Table 16 Surplus for ONGC from Gujarat fields ($/bbl)

Refinery	Option A	Option B	Option C	Option D
Koyali	0.57	1.08	4.17	3.53

- As this table shows, Option A and Option B are not sustainable for ONGC. Under Option D, given the exploration commitment of 2.3 $/bbl, the net left is $1.23/bbl. Thus, ONGC should negotiate for import parity prices for Gujarat crudes.

Strategy for Cauvery basin crude

Existing and potential customers

- The CBU refinery of Chennai Petroleum Corporation (CPCL) takes the entire Cauvery basin crude. However, since CPCL owns both Chennai and CBU refineries, it can be assumed that Chennai refinery would not compete with CBU refinery for this crude.
- Vizag refinery does not process Arab Light crude to which the Cauvery crude has been benchmarked. Since no assumption can be made regarding the refinery flexibility in processing different variety of crude, it cannot be assumed that the refinery will be able to process the Cauvery crude.
- Moreover, the cost of transporting the Cauvery basin crude to the Vizag and Kochi refinery will be prohibitive. The crude would first have to be moved to Chennai from where it will have to be transported via sea route to Kochi refinery and perhaps via road to Suryasayanam from where it will be moved to Vizag.
- CBU refinery is also handicapped by the lack of access to any other source of crude. It does take in 0.054 MMTPA of imported crude but that represent only 9.32% of the total refinery throughput. These imported crudes are

transported via road from Chennai, which makes the cost of transportation as high as Rs 284/MT. Due to this high cost of transportation, CBU is mainly dependent on Cauvery basin crude which currently represents 75% of its throughput.

Evaluation of options

- The difference between Option A and Option C is $3.29/bbl, which then represents the negotiating margin for ONGC and the refinery. The comparable international crude identified for the purpose of base price is Arab Light.

Premium factors for ONGC

Security of supplies

- If CBU decides to import 434 TMT of crude to replace Cauvery basin crude, in the event of a supply disruption, it can face an increase in the fixed cost to the extent of Rs 0.919/MT ($0.002/bbl).

Augmentation of infrastructure for imports

- The cost of moving the crude via road is 0.85 Rs/MT/Km[d]. Thus, if the CBU decides to replace the Cauvery basin crude with imported crude, it will have to take this extra quantity through road. The current estimated costs of transporting 54 TMT is Rs 15 million which will rise to Rs 138 million if it takes 434 TMT of imported crude. Thus, CBU has to incur Rs 283/MT as the cost of transporting the crude from Chennai to Panangudi.

Letter of credit charges

- If CBU is required to pay even 0.1% higher LC charges, its cost of imports will rise by Rs 6.69/MT ($ 0.019/bbl). Thus, ONGC can ask for a premium to this extent on this account.

Foreign exchange risks

- For CBU refinery, a 1% depreciation in rupee will cause a rise of Rs 74.44/MT ($0.220/bbl) for the month of January 2002 on import of Arab Light. Thus, ONGC is in a position to charge a premium to this extent.

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[d] Data from OCC

Summary table for Cauvery basin

Table 17 Summary of premiums for Cauvery basin

	Rs/MT	$/bbl
Premium factors for ONGC		
Augmentation of facilities for imports	283	0.839
Cost of international procurement		
Letter of credit charges	6.69	0.020
Exchange rate risks	74.44	0.221
Total	365.049	1.083

Strategic option

- Due to the fact that Cauvery's production quantity is very low and because of the fact that ONGC does not have the required infrastructure to move the crude to any other refinery, ONGC may not get the import parity price for its crude due to prohibitive costs of moving crude to alternate refineries. It may have to negotiate for FOB price only.
- Applying this premium to the two FOB options for setting the base price, the following surpluses emerge.

Table 18 Surplus for ONGC from Cauvery field ($/bbl)

Refinery	Option A	Option B
CBU	1.48	1.97

- Under Option B, the surplus left is $ 1.97/bbl which is $ 0.33/bbl less than the surplus of $ 2.3/bbl required by ONGC to fund its exploration activities. Thus, ONGC should try to negotiate at least that price at which $ 0.33/bbl higher than the price under Option D. This is not a big amount considering that the pricing on FOB would save the refinery the freight from Middle East to East Coast India.

Strategy for KG basin crude

Existing and potential customers

- The total installed capacity of the Vizag refinery is 7.5 MMTPA. The total crude throughput of the refinery in the year 2000-01 was 6.4 MMTPA which means that KG crude fulfils only 3.9% of the refinery's demand for crude. The Vizag refinery takes 2.5 million tonnes of Ravva crude and 3.8 million tonnes of imported crudes. Thus, apart from the fact that Vizag refinery is

not dependent on the KG crude for its processing needs, it also has some other options for sourcing the crude.

- The transportation cost incurred by ONGC in moving this crude is high because of the small and scattered fields marking the KG basin, which means that crude moves via road tankers raising the transportation cost. It could be thus concluded that the prospects of this crude moving to the other two refineries in the region – Haldia and Chennai – are very bleak.

Evaluation of options

- The difference between the price received by ONGC from the refinery under the FOB option and the import parity option is $3.36/bbl, which then represents the negotiating room for each party. The comparable international crude identified for the purpose of base price is Arab Light.

Premium factors for KG basin crude

Security of supplies

- This factor does not seem to be of much relevance for the KG crude, which forms only about 4% of the total throughput of the refinery, which is also taking Ravva crude (40% of the throughput). Thus, no premium can be accorded to KG crude on this account.

Augmentation of infrastructure for imports

- Replacing the KG crude with imported crude should not pose any problem for the refinery since the additional imports would be very small and there would be no port constraint either as currently the port occupancy is only 78%.

Letter of credit charges

- This argument does not apply to the Vizag refinery in this context since it is already importing a large quantity of crude and importing an additional amount of 0.25 million tonnes would not raise the import cost by much.

Foreign exchange risks

- The Vizag refinery is already exposed to a high foreign exchange risk. Importing additional crude to replace the KG crude will not increase this risk by much since the quantity is very small. Moreover, it can't be positively said that KG crude can be replaced only by imported crude in the light of the

presence of Ravva crude field. Thus, premium can't be claimed by ONGC on this account also.

Freight diseconomies

- After the dismantling of APM, HPCL has decided to import its requirement on its own. The combined requirement of the two refineries of HPCL – Mumbai and Vizag is 7.24 MMTPA. The quantity of KG crude is just 3.45% of this quantity. Thus, bringing this additional quantity of crude should not pose any problem for the refinery.

Discount factors for ONGC

High level of BS&W in KG basin crude

- As provided by ONGC, the level of BS&W is 0.3%, which is much above the internationally accepted level of 0.02%. Any crude with BS&W higher than 0.02% is discounted in the international market.
- As submitted by ONGC, it takes around Rs 100 million to desalt 1 MMT of crude. Thus, the annutised capital cost of desalting the KG crude will be Rs 15.53/MT. This has been used as the proxy discount that ONGC may have to yield to the refinery.

Summary table

Table 19 Summary of discount for KG basin crude

Discount factors for ONGC	Rs/MT	$/bbl
BS&W in KG crude	15.53	0.046
Total discount	15.53	0.046
Net discount	15.53	0.046

Strategic options for KG basin crude

- ONGC has got no option but to sell this crude to the Vizag refinery. Vizag, on the other hand, has two other sources of crude procurement, one of which is indigenous and is contributing significant quantity. Thus, it is very unlikely that ONGC will get import parity price for KG crude. Thus, ONGC should aim for FOB based pricing for this crude.
- If the base price is indeed set at FOB, then the surplus left for ONGC after meeting all the claims like tax, cess, and other direct and indirect costs is shown below.

Table 20 Surplus for ONGC from KG basin ($/bbl)

Refinery	Option A	Option B
Vizag refinery	0.75	1.24

- As this table shows, this pricing option does not seem to be sustainable for KG basin. It needs about $2.3/bbl to fund its commitment in E&P but this field will not generate enough surpluses for the same. The lowest gap between surplus generated from these options and exploration commitment is $1.06/bbl. Thus, ONGC should negotiate for at least that price which enhances the surplus by $1.06/bbl.

Strategy for North Eastern crudes

Existing and potential customers

- Haldia refinery is processing only the imported crude. Moreover, since there is no infrastructure to move crude from North East to Haldia, Haldia is not a potential customer for North Eastern crudes.
- Digboi refinery, however, is a potential customer though it is not processing the ONGC crudes currently since there is a pipeline carrying the crude from Moran CTF to Digboi refinery.
- OIL being a major producer in the region, refineries have an alternate option for crude procurement in OIL. With a volume of only 1 MMTPA, there isn't much bargaining power with ONGC.

Evaluation of options

- The difference in the price realisable by ONGC under the FOB and IPP options is $4.92/bbl. This represents the negotiating margin for ONGC and for the refineries. The comparable international crude identified for the purpose of base price is Bonny Light.

Premium factors for ONGC

Alternative options for refineries and ONGC

- The imported crude to Barauni refinery is transported via the Haldia-Barauni pipeline, which is owned by IOC and has the capacity of 4.2 MMTPA. Given the installed capacity of Barauni refinery as 4.2 MMTPA and the average throughput of 3.1 MMTPA, the pipeline capacity is not a constraint.

- The average occupancy at the Haldia port during the year 2000-01 was 63-69% (table 10.5). Given the total crude oil import volume at the port of 6.2 MMTPA, importing an additional 0.3 MMTPA (to replace the ONGC crude) should not pose any problem for the Barauni refinery.
- Bongaigaon refinery processed around 0.082 MMT of imported crude in the year 2000-01. The imported crude to Bongaigaon refinery is transported via the Barauni-Bongaigaon pipeline with the capacity of 3 MMTPA. Thus, this pipeline is not a bottleneck for BRPL.
- Digboi and Numaligarh are heavily dependent on the OIL's crude and hence the chances of their importing the crude to replace the ONGC crude are very less.

Security of supplies

- OIL is the major producer in the region and can supply crude oil to all the refineries. Moreover, out of total throughput of 11 MMTPA for the region, ONGC's 1 MMTPA is cannot be perceived to have any substantial effect on the security of supplies in the region. As such the region is accounting for only 8.5% of the total imported crudes in the country. So a disruption of 62.21 MMT would not have a huge impact on the region.

Letter of credit charges

- Digboi cannot be expected to pay a premium on this account because it is processing only the OIL's crude. OIL also accounts for 98% of the Numaligarh refinery's crude throughput and hence the refinery's need for international crude is very less. Also, Barauni and Guwahati refineries, being a part of IOC which is a Fortune 500 company, may not pay a higher LC charge on imports. And since Bongaigaon is importing only 0.082 MMTPA of crude, this factor is not very important for it also.

Freight diseconomies

- The Barauni refinery is already taking 2.4 MMTPA of imported crude and taking an additional quantity of 0.3 MMTPA would not raise the import cost on any account.
- Digboi does not process any imported crude and hence will be not be affected. Numaligarh takes only 1.3% of its crude throughput from ONGC and hence is in a confortable position.
- The Guwahati refinery takes 0.310 MMTPA of ONGC crude and if it decides to replace it by imported crudes, it can be easily clubbed with Barauni and

Haldia (both owned by IOC) and hence would not necessitate any additional costs of imports for the refinery.

Discount factors for ONGC

High BS&W in crudes

- The average BS&W in the Assam crudes is 0.2% which is higher than the international standard of 0.02%. ONGC would either have to bring the crude to the international standard before dispatching it to the refineries or it would have to accept a discount to the extent of the cost which has to be incurred in doing so.
- It costs about Rs 100 million to desalt 1 MMT of crude. Thus the annutised cost of desalting 2 MMT of crude can be estimated as Rs 15.53/MT (0.046 $/bbl).

Summary table

Table 21 Summary table for NorthEastern crudes

	Unit	Barauni	Guwahati	Digboi	BRPL	NRL
Discount factors for ONGC						
BS&W problem	Rs/MT	15.53	15.53	15.53	15.53	15.53
Total Discount	Rs/MT	15.53	15.53	15.53	15.53	15.53
Average Net Discount	Rs/MT	15.53	15.53	15.53	15.53	15.53
Average Net Discount	$/bbl	0.046	0.046	0.046	0.046	0.046

Strategic option

- Given the fact that ONGC does not have any alternate option to sell its crude and given the fact that ONGC's crudes are not of international quality, it will be difficult for it to demand import parity price for its crude. Thus, out of the four pricing options mentioned earlier, only two are possible – those based on FOB.

Table 22 Surplus for ONGC from NE crudes ($/bbl)

Refinery	Option A	Option B
Barauni	1.26	1.77
BRPL	1.26	1.77
Guwahati	1.26	1.77
NRL	1.26	1.77
Digboi	1.26	1.77

- If ONGC can negotiate for an additional \$ 0.53/bbl under Option B, it can make the required surplus of \$ 2.3/bbl. This amount of \$ 0.53/bbl is not high considering the fact that pricing crude on FOB effectively saves the freight from Nigeria to East Coast India.

PART 2 – NATURAL GAS

- The objective of the marketing strategy of gas produced by ONGC is to maximise the netback to ONGC from selling gas. This can generally be achieved by selling gas to the market segment consisting of the high imputed value sectors like power generation, fertilisers, captive power, etc. at prices approaching their opportunity costs.

Estimation of gas demand

- TERI estimates of sector-wise gas demand is as follows:

Table 23 Total gas demand (MMCMD)

	Existing	2006/7
Power	49.37	71.79
Fertiliser	40.22	40.22
Cement	4 84	6.87
Paper and pulp	3.35	5.04
Glass	1.87	2.65
Total industries *	10.06	14.56
Captive	5 78	10.36
Total	105 43	136.93

- Does not include industries other than cement, paper and glass.

- To find the demand at different levels, the imputed value methodology has been used. Accordingly, the demand for gas at various prices is as follows:

Table 24 Demand of gas at various prices (MMCMD)

	Existing	2006/7
Demand at gas price \$3.50/MMBtu		
Power	46.33	68.75
Fertiliser	40.22	40.22
Industries	1.87	2.65
Captive	5.78	10.36
Total demand	**94.20**	**121.98**
Demand at gas price \$4.50/MMBtu		
Power	21.04	32.80
Fertiliser	40.22	40.22
Industries	1.87	2.65

Captive	5.78	10.36
Total demand	68.91	86.03

Gas marketing strategy

A better fuel oil linkage

- Though domestic gas price is now linked to international prices of fuel oil the linkage is under review and full parity with fuel oil is expected in the near future. The gas price should get another boost in 2004 when LNG arrives at Gujarat. Thus, the gas price may pass through some intermediate stages before fully market driven prices are re-introduced.
- The price is determined and notified by GAIL with the approval for the Ministry for every quarter depending upon the average price of the following basket of fuel oils (with equal weights to each type) based on the figures obtained from Platt's Oilgram for the previous quarter.
  - Cargoes FOB, Med Basis, Italy (1% Sulphur)
  - Cargoes CIF NEW Basis, ARA (1% Sulphur)
  - Singapore, FOB, HSFO 180 cst (3.9% Sulphur)
  - Arabian Gulf, FOB, HSFO 180 cst (3.9% Sulphur)
- The government has allowed fuel oil linked prices in two other cases, Panna-Mukta-Tapti and Ravva. In the first case there is a ceiling price of $3.11/MMBtu and in the second case the ceiling price is $3/MMBtu. Accordingly, a ceiling for ONGC may be imposed somewhere between $2.5-3.0/MMBtu.
- ONGC should try to negotiate a high ceiling price but it may be difficult to do so. In view of the recent experience with high oil prices, consumers would be sensitive to the ceiling.
- It would be more feasible for ONGC to negotiate a better fuel oil basket. So long as the ceiling price is acceptable, the consumers may be less sensitive to a higher price within the ceiling. This could be done by choosing only low sulphur fuel oils, altering the weight in favour of low sulphur fuel oils in the basket and by changing fob prices to cif.

Pooled price for LNG

- So far as is known, the cif LNG prices at the Gujarat coast would be:

  At $18/bbl JCC: $2.55-2.75/MMBtu
  At $25/bbl JCC: $3.45-3.80/MMBtu

- Adding 40 cents/MMBtu for regasification, the gas price ex-receiving terminal would come to $2.95-4.20/MMBtu. We may add 10 cents/MMBtu for locations in the southern and eastern coast for additional ocean freight.
- If the gas is put into the HBJ pipeline, it would reach consumers in western and northern India with the addition of another $1/MMBtu as the transportation cost. The price to HBJ consumers would rise from $3.95-$5.20/MMBtu as the crude oil price goes from $18/bbl to $25/bbl.
- The domestic gas price is already a pooled price with customers paying the same price for ONGC gas and costlier gas from private fields. The proportion of costly gas would increase if LNG is also pooled in. One way of pooling would be to mix 20 MMCMD of LNG with 60 MMCMD of gas now available (not counting the north-east).
- As we have seen earlier, regasified LNG would cost $3.45/MMBtu at a JCC price of $25/bbl. If this has to be sold at $3.25/MMBtu (the expected netback at Dahej based on imputed values of customers along the HBJ), the domestic gas price has to be capped at $3.2/MMBtu. This does not pose a problem. However, if LNG has to be covered at a JCC price of $30/bbl, the domestic cap would be $2.9/MMBtu. If the expected netback is lower, the cap will be lower. If the proportion of domestic gas is taken to be lower to cover decreasing production, the cap would be lower still. The implication for ONGC is that if pooling is unavoidable, ONGC must be fully involved in the price fixing exercise.

NELP Gas

- ONGC would be free to get a better price for gas from NELP blocks. Private gas producers would be similarly placed. When LNG becomes available, the price of this gas could be raised to import parity. However, most of this gas is expected to be found around Gujarat or Andhra Pradesh where gas-to-gas competition may keep the price down. In view of the possibility of increasing the gas price, it would be prudent not to sell this gas on long term contracts. At least, the price should be kept flexible.

Individual vs. bulk sales

- ONGC may avoid a part of selling cost by selling gas in bulk to GAIL or other such agencies who would undertake the tasks of transport and marketing. This would be a good choice if a number of agencies were available to do this job. In such a case, the agency could be selected through competitive bidding and the netback to ONGC could be maximised. Bulk selling may be more

feasible in cases where the marketing risk appears to be large. These decisions could be taken on the merits of the particular case.

- As in the case of gas sold through GAIL, the choice of fuel oils would be important, as would be the price ceiling or the linkage. These could vary between regions depending on the customer profile. ONGC would need to have a clear idea of the purchasing power of the customers even while negotiating bulk sales.

Coping with variable prices

- Where ONGC is free to price the gas, the uncertainties linked with a variable gas price could be avoided by selling the gas at a steady price. This would be welcome by Indian gas consumers as many of them are in the public sector and are, therefore, averse to taking risks. Hardly any gas seller would, however, agree to a steady price which eliminates the possibility of large gains. A compromise acceptable to both the buyer and the seller would be a variable price subject to a floor and a ceiling. Generally, the ceiling would be dictated by the cost of alternative fuels to the buyer whereas the floor would be a function of the production cost.

Contract conditions

- Gas consumers in India may have difficulties in signing long term contracts with stiff take-or-pay provisions. Gas suppliers who depend on project finance for developing their fields may find such terms unavoidable. ONGC could have an advantage here, over other suppliers. If the market is competitive, ONGC could offer more flexible contract conditions if that leads to a higher market share. In some cases, a similar advantage could be derived by offering Rupee prices in stead of Dollar denominated prices.
- The pricing and other conditions would have to be innovative if gas is to be sold to industrial consumers. Most of these may be able to afford only intermittent supplies, depending on movements in coal and fuel oil prices. A two-part transportation tariff in which fallback suppliers do not pay capacity charges could help in developing such customers. It would be in the interest of ONGC to influence regulatory policy in this regard.

PART 3 – VALUE ADDED PRODUCTS

Liquefied Petroleum Gas

Overview

Industry snapshot

- Indian LPG market broadly classified into two categories – bottled and bulk, with bottled LPG, primarily domestic, dominating the market (90%)
- Growth in LPG sales (10.6% over the last decade) petering down with near saturation in urban markets as waiting lists get liquidated
- Rural marketing more challenging – well established trade channels a prerequisite for successful entry

Options for ONGC

- Continue existing marketing arrangements with OMCs (Oil Marketing Companies) with some renegotiations, or explore the following - direct marketing to bulk and retail consumers/ tie ups with parallel marketers/ exports

Evaluation of options

- *Direct marketing:* Limited bulk LPG market necessitates entry into retail marketing for full product offtake. ONGC would be unable to compete head on with OMCs on account of lack of marketing infrastructure, especially bottling plants. ONGC's filling charges likely to be twice as high as those of OMCs
- *Tie up with parallel marketers:* Current trade volumes only a fraction of ONGC's production. Moreover, operators already rethinking on continuing operations on account of sustained losses
- *Exports:* Lower export realisations and investments in new infrastructure to export LPG render the option unattractive. In addition, declining production makes it difficult to secure buyers

Recommendations

- **ONGC to continue current marketing arrangements with OMCs with negotiations on fractionator gate prices which currently are well below import parity prices**
- **Should offer near import parity prices which affect a win-win situation for both ONGC & OMC**

- **Discount of 5% (say) ensures full offtake of production for ONGC; procurement savings in excess of Rs 100 crores for OMCs; and net gains for ONGC of the order of Rs 650 crores**

Direct marketing of LPG

Bulk vs bottled sales

- As a marketing option, bulk sales score over retail as they entail substantially lower investments as compared to retail which requires investments in bottling plants, dealerships, distribution, etc.
- Demand for bulk LPG in the country, however, is fairly limited. LPG requirements by the total industrial/commercial sectors add up to 638 TMT only. In contrast, ONGC's current LPG production aggregates 1,214 TMT. Thus, even if ONGC were to capture the entire industrial/commercial market in the country, the total offtake would account for only half of its production, necessitating retail sales of the remaining.
- With ONGC's production facilities located in the western part of the country, it would not be a competitive supplier throughout the country as freight costs are substantial. ONGC's target markets will, thus, be limited to the western region, which accounts for only a fifth[e] of the total bulk LPG market.

Economics of bottling

- Bottled LPG from ONGC would have to be competitive with sales from established players in the industry – IOC, BPC and HPC.
- Setting up of a bottling plant entails substantial investments. While other OMCs have already recovered their investments in LPG marketing infrastructure by and large, ONGC would have to recover its investments from prices dictated by the OMCs.
- Typical investments for a bottling plant of 44 TMT could be pegged at Rs 30 crores. Inclusive of operating costs, filling charges for such an investment are expected to be about Rs 2,091/MT. Current filling charges for OMCs, however, are only Rs 970/MT. ONGC would be unable to match prices offered by OMCs.

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[e] Bulk PSU LPG sales in 1999/00 in the Western region of 100 TMT accounted for 19% of the total bulk LPG sales of 534 TMT

Exports

- LPG will remain in deficit over the Tenth Plan period, necessitating large scale LPG imports into the country. Exports are unattractive in the ensuing scenario given the low realisations from exports as against domestic prices at import parity.
- In addition, ONGC would have to invest in new infrastructure to export LPG - a dedicated pipeline to the port, storage facilities at the port, loading arrangements, cryogenic facilities for transportation, etc. The costs incurred in development of such facilities would have to be borne out of the export earnings. The net realisation from exports would, thus, be further reduced.
- The declining production of LPG becomes a critical issue while considering the viability of exports. A buyer, in general, would tend to lock on to a secure supply source, i.e., where availability is not an issue.

Sales to parallel marketers

- The parallel market trade is fairly limited, with total imports by parallel marketers aggregating only 178 TMT in 2000/01. The trade in the western region is further limited and distributed amongst a number of players - Bharat-Shell, SHV, Hindustan-Domestic Oil & Gas Co Ltd., and Reliance.
- A strategic tie-up with parallel marketers would assure offtake of only a fraction of ONGC's total output
- Parallel marketers have had to compete with PSU sales, subsidised by the Government through the oil pool account. As a result, over the years parallel marketers have suffered substantial losses and have been threatening to pull out[f] of the business, unless the subsidies are extended to their operations as well.

Commercial agreements with OMCs

- Given a deficit situation in LPG supply in the foreseeable future, market prices for LPG, would in general be at import parity.
- Current fractionator gate prices for ONGC are well below import parity (about 40%)
- ONGC should seek *near* import parity prices which translate into procurement savings for OMCs and at the same time boost ONGC's realisations substantially from current levels

[f] "LPG MNCs threaten to exit, seek subsidies", Business Standard, 18th August 2001

- A 5% discount on import parity price would affect procurement savings in excess of Rs 100 crores for OMCs
- For ONGC, even with a 5% discount, its realisation would be higher by Rs 5,895/MT at Hazira and Rs 5,420/MT at Uran. On an annualised basis, the net gain for ONGC would be about Rs 650 crores (Rs 360 crores at Hazira and Rs 290 crores at Uran).
- ONGC will not be able to contract take or pay obligations with OMCs as OMCs have the upper hand. If OMCs fail to lift supplies, ONGC will have a containment problem at hand. Moreover, OMCs have fall-back arrangements for alternative supplies.
- With ONGC's core competence in production, it would be prudent for ONGC to synergise its operations with OMC's, rather than competing head on with them for a share in the LPG retail business.

Naphtha

Overview

Naphtha demand supply position

- Projections for naphtha demand and supply indicate towards an overall naphtha surplus of 4.9 MMT in the year 2006/7 out of which the Western region, where all of ONGC's production is concentrated, accounts for 1.4 MMT against ONGC's production of 1.1 MMT.

Current status

- Naphtha demand is concentrated in bulk consumers like power, fertiliser and petrochemical with very little demand from other industry sections. IOC is the dominant Oil Marketing Company (OMC) in the country.
- The price received by ONGC on selling naphtha directly is less than that received on selling naphtha to the OMCs, despite the expectations otherwise due to hefty marketing margin imposed by OMCs, because the former sales are made in distress and hence ONGC has to give a discount to the buyer.
- In the period May 2000 to February 2001, ONGC also exported about 300 TMT tonnes of naphtha with a realisation that was even lower than that realised on spot sales to domestic consumers due to presence of high infrastructure costs.

Options for ONGC

- Continues to sell naphtha to OMCs under a renegotiated contract or undertakes direct selling, goes for vertical integration, bypasses naphtha production or exports its naphtha.

Recommendations

- **While ONGC may try and negotiate for a share of marketing margins it unlikely that OMCs will agree as has been in the case in the past. However, the import parity price remains attractive and ONGC should attempt to enter into long term contracts with the OMCs even if it has to give a small discount on this price.**
- **Export parity price on naphtha is about 14% lower than the import parity price but 10% higher than its imputed value vs. LNG. Therefore export of naphtha must always remain a second option if ONGC cannot realise the import parity price from OMCs or there is an uncontainable surplus.**

Evaluation of options

Renegotiations with OMCs

- Renegotiating with OMCs for a share in marketing margins will increase the price realisable for naphtha but will also increase the offtake uncertainty in view of surplus in naphtha unless ONGC is willing to give some price discount which in turn may neutralise the gain in price due to share in margins.
- This remains true for renegotiations for a long term sales contract that will not be forthcoming unless ONGC yields some discount on price.

Selling naphtha directly

- As ONGC's naphtha production is concentrated in the western region, it can sell directly to the consumers in this region only since carrying it further away would render the product uncompetitive with respect to naphtha production in the targeted region.
- Selling directly under long term contract will raise the administrative cost of selling naphtha since ONGC will have to enter into contract with each and every customer.
- It is also possible that long-term contracts, not nearing their maturity date, are currently in force between the OMCs and consumers in which case it

would be difficult for ONGC to break the existing bonds. The problem is compounded by the projected naphtha surplus in the western region.

Pricing issues

- The impact of LNG would be more pronounced on the prices of naphtha because gas can replace naphtha in many applications, especially fertiliser production and power generation. Shell is planning a LNG terminal at Hazira and Petronet is building a LNG terminal at Dahej. Thus, within few years, there is a possibility of LNG flooding the Western sector. In such a case, the naphtha upliftment will fall and so will the prices.
- The cost of feedstock per tonne of urea produced is higher in the case of naphtha than using gas and LNG. Moreover, the capital cost of setting up the new urea plant is also lower for a plant using gas/LNG than for a naphtha-based plant. With the costs of conversion of an existing naphtha based unit into a gas-based unit being negligible, one expects that the fertiliser plants in the country will shift to gas.
- Imputed values methodology estimates that for naphtha price of Rs 7085/MT, the fertiliser plant will be indifferent between using naphtha and using gas landing at $3.68/MMBtu whereas the import parity prices, according to the current methodology, are higher than this price which means that gas will be preferred to naphtha if prices are set at import parity.
- Thus it is expected that naphtha prices will fall once LNG is delivered to India.

Price cutting

- Cutting prices in a collusive market to undercut other competitors will result in a price war in which the company with longer staying power will survive. In this context, both OMCs and ONGC are on equal footing since selling naphtha is not the main source of income for both and shutting down naphtha production is not an option for both. This would, however, result in revenue loss for both companies. Hence maintaining the current price structure is advantageous for ONGC.
- Other possible pricing bases like energy equivalent pricing, calorific value equivalent pricing and yield equivalent pricing should be explored.

Vertical diversification

Acquiring marketing PSUs

- Since ONGC had made clear its plans to enter into downstream and to bid for oil PSUs being privatised, this analysis explores the benefits, if any, for naphtha sales if any one of marketing PSUs comes under ONGC's control.
- The total all-India sales by BPCL and HPCL for the year 2000-01 were 1335.8 TMT and 1222.8 TMT[g] respectively. Sales in the western region over the same period for BPCL and HPCL were 708.1 TMT and 806.7 TMT respectively. BPCL sold 440.2 TMT less whereas HPCL sold 203.6 TMT more than its naphtha production in the domestic market for the year 2000-01. Comparing these with the ONGC's production of 1688.7 TMT last year, it becomes clear that none of the PSUs will be able to sell entire ONGC's production in the domestic market.
- However, it will bring some benefit at the different production centres individually. At Gandhar, ONGC sells entire quantity to BPCL, which sells it to GPCL Dahej. Thus, at Gandhar, having BPCL within ONGC will lead to internalising of marketing margins made on such sales. The same is true for Ankleshwar and Uran. The situation is not very different at Hazira because the naphtha produced at Hazira is primarily sold through HPCL.

Setting up a downstream plant

- For ONGC, the main benefits of setting up a plant that consumes naphtha are –

1. No costs associated with sale of naphtha.
2. No reliance on either OMCs or private sector for naphtha offtake.

- However, ONGC's naphtha production is projected to decline by about 22% over the four-year period from 2002/3 to 2006/7. Assuming the same declining growth rate, the naphtha production will decline to 498 TMT by 2019/20. 1.1 million tonnes of naphtha can support a power plant of 1115 MW or a fertilizer plant of 2 MMTPA. But with declining production, it will need to purchase 602 TMT of external naphtha in order to sustain these capacities in the year 2019/20. This will bring, apart from fuel costs, additional costs in the form of administrative and marketing costs.

[g] Source: IPR, March 2001

- On the product marketing side, ONGC will have to compete against plants that may have switched to LNG from other fuels for better economics and thereby giving lower price.
- Moreover, this strategy involves a high initial capital investment with long pay back period.
- Then ONGC will have to enter into multiplicity of contracts with various stakeholders, which will again increase the costs.
- This strategy would, therefore over a long term, mean a complete diversification of business activities of ONGC, the suitability of which depends on various factors other than mere profits and hence cannot be completely evaluated given the limited scope of study.

Bypassing naphtha production

- While the whole economics of the process are difficult to work out given the limited scope of the study, it appears reasonable to conclude that this option would entail losses for ONGC apart from not solving the problem entirely since NGL will have to be disposed of apart from losing the revenue from SKO and LPG.

Naphtha exports

- The price volatility in the international market and declining production point towards low attractiveness of the export market. However, there is an import demand for around 49 million tonnes from the countries in the Asia-Pacific region. The bulk of the demand comes from Japan followed by South Korea. China is another market that will import increasing quantities of naphtha in the coming decade followed by Taiwan. Even Singapore has the demand that can absorb ONGC's production.
- By exporting its naphtha, ONGC will be able to circumvent competition from OMCs and will be able to earn international price for its naphtha.
- If, due to domestic surplus, the prices in the domestic market were to fall to near or below export parity level, exports of naphtha will become attractive due to higher price realisation given that ONGC's production facilities are concentrated in and around ports. This also holds good in the event where LNG supplies in the country force a downward revision in naphtha prices.

PART 4 – RISK MANAGEMENT ISSUES

Introduction

- ONGC is primarily an oil exploration and production company though it has also developed a portfolio of refined products like LPG, Naphtha and Kerosene. And with the prices of the petroleum products also linked to the crude prices, it means that virtually all revenue is linked to the crude oil prices.
- However, there are few other important factors that are important while analysing the need for hedging. These are - the ownership structure of the company, the ownership structure of the industry as a whole and the risk return perception of the investors.

Volatility in crude oil prices

- ONGC produces about 23 MMT of crude every year. An intermonth fall of about $1/bbl in crude prices internationally will lead to a fall in revenue to the tune of Rs 646 million (assuming equal deliveries in every month and an exchange rate of $1=Rs46).
- For the past many months, prices have been in the OPEC's target range of $22-$28/bbl. Given the fact that many OPEC countries balance their budget within this price range and given the influence of OPEC on world oil production, it can be said that the prices would generally remain in the OPEC's target price band for the foreseeable future. This will significantly reduce the price risk for ONGC.

Ownership structure of the Indian oil industry

- The government of India heavily represents the present equity structure of major companies in the Indian oil market.
- This means that the sale of crude oil by upstream companies to refineries is mainly a transfer by one public sector organisation to another, both under the purview of one ministry. In such a structure, fall in prices will benefit one entity while harming the other with overall gains/losses being passed off to the government since it is the major shareholder or to the consumer if free pricing is followed.
- Indulging in hedging in such a structure only ends up raising the costs of the final products for the consumer.

Management issues

- The process of hedging is as dynamic as the market itself. Quick decision-making and risk taking are the two prerequisites for profitable hedging. Normally public sector companies are not known for providing environment conducive to breed these qualities in their management.
- In a public sector set up, the mistakes tend to be magnified because the money involved is state's money whereas the successes tend to go unrewarded. This attitude acts as a dampener on quick decision-making since few decisions in the initial years will go wrong. Thus, decision-making in such an environment tends to be very hierarchical and cautious.
- Detail guidelines, which are both binding as well as broad and policies that lay down the permissible risk exposure level certainly help in the objective of the hedging.

Participation by International oil majors in hedging markets

- International exploration and development companies are not known to be actively involved in hedging. One of the principle reasons is the perceived risk return trade off for their investors and markets alike, which means that higher the risk company is taking, the higher is the return it is expected to generate. If an oil company hedges its crude oil sales, it is locking the price it will get for it, irrespective of the actual price in the market. This then precludes the opportunity of higher returns on its crude oil and will reduce the overall organisational returns, which will be against the expectations of its investors and the market. This will reduce the return on the equity of the company due to depressed expectations.

Participation by exporting countries

- The major producer countries, organised under OPEC, are not very active in the hedging markets. This is primarily due to the power OPEC has in influencing the price of crude oil to its advantage.
- Moreover, ever since the control of crude oil passed over from oil majors to the national oil companies of the OPEC countries, these companies have entered into long term supply contracts with the national oil companies of the consuming countries and have little presence in the spot market.
- The world spot trade in concentrated in few marker crudes like Brent, Dubai and WTI, which represent about 3-4% of the international trade in crude[h].

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[h] Paul Horsnell and Robert Mabro: "Oil Markets and Prices" Oxford Institute for Energy Studies, Oxford University Press

The rest of the traded crude oil moves under term contracts. Moreover, the spot trade is concentrated in few regions of the world.

- The spot trade in Asia is also very thin. The bulk of crude oil moves either through integrated channels, between state oil corporations of the same country or through term contracts with regional buyers.

Conclusions

- It can be concluded that the need for hedging varies from company to company. The starting point for any risk management strategy is an analysis and quantification of the risks an organisation is facing and the sensitivity of the project evaluation to the underlying prices in the international market.
- From the precluding analysis, it can be said that ONGC does not face any substantial price risk in the view of the strategies adopted by OPEC. In fact, ONGC seems to gain from the pricing strategies of OPEC. Additionally, the organisational structure of ONGC does not encourage hedging since government is the majority shareholder in the company.
- One option for ONGC is to enter in the hedging market through a financial intermediary or through a separate trading arm within the conglomerate but at an arms' length with the exploration and development function to ensure transparency and accountability. Involvement through financial intermediary will involve transaction costs irrespective of the outcome of the hedge which may weigh heavy on the balance sheet.

PART 1
Crude Oil

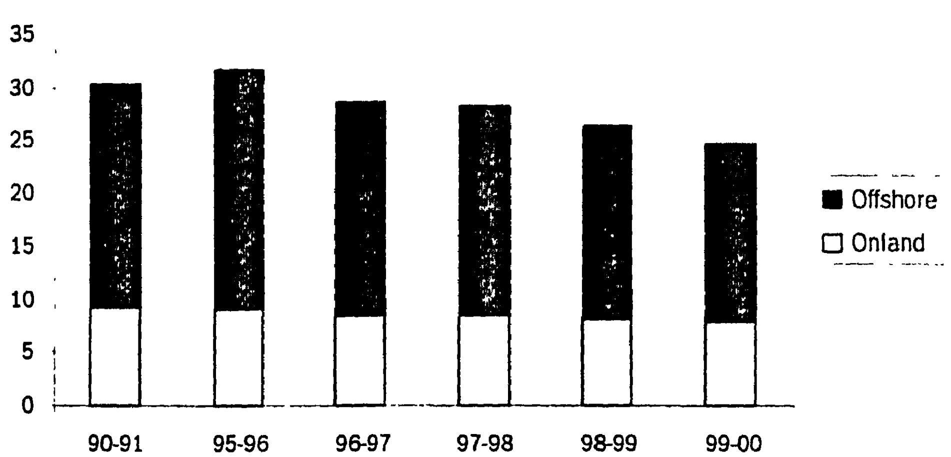
1 Introduction

Profile of ONGC

The upstream oil sector in India is dominated by two National Oil Companies – Oil and Natural Gas Corporation Limited (ONGC) and Oil India Limited (OIL), together accounting for about 88% of country's present oil and gas production, with rest being accounted by joint ventures and private companies. While ONGC's share of nearly 77% of indigenous crude oil production and 82% of country's gas production is spread across six fields in five regions of the country, OIL's share of 10% of indigenous oil production and 6% of gas production is confined mainly to Assam, Arunachal Pradesh and Rajasthan. Oil and gas production by OIL in 1999-00 had been 3.3 MMT and 1729 MMCM[a] respectively, whereas that by ONGC in the same year had been over 24 MMT and 23252 MMCM respectively.

The yearly oil and gas production by ONGC for the last decade is shown in Figure 1.1 and 1.2 respectively.

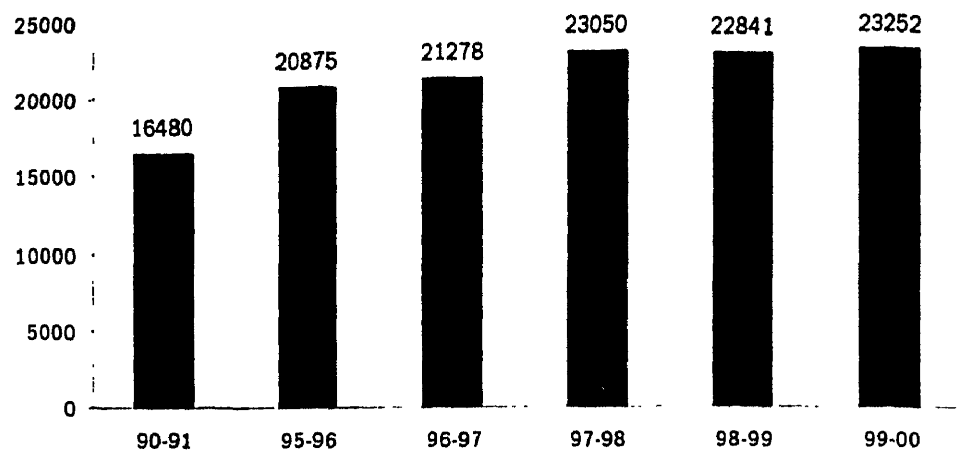
Figure 1.1 Oil production of ONGC [Million Tonnes]



Source. Basic Statistics on Indian Petroleum and Natural Gas, 1999-2000, MoPNG

[a] Oil and gas production figures of ONGC and OIL from Basic Statistics on Indian Petroleum and Natural Gas, 1999-2000.

Figure 1.2 Gas production by ONGC [Million Cubic Meters]



Source. Basic Statistics on Indian Petroleum and Natural Gas, 1999-2000.

These figures show a stagnating trend over the years.

Given that India is importing about 70% of its crude oil requirement and that gas is emerging as a major fuel of the future, it is essential that domestic production of both be increased. Being the major upstream oil company, much of the responsibility of reserve accretion and production falls on ONGC. However, the Xth Plan presents a shortfall in achievements of production targets set by the Planning Commission during the IXth Plan.

Table1.1 Expected percentage achievement in the IX plan

Activity	Planning Commission Targets	Achievement upto March 2001	Likely Achievement in IX plan	% ac[illegible]
Oil & Condensate production (MMT)	144.894	104.39	129.39	
Gas Production (BCM)	119.041	92.57	116.57	

Source. Tenth Plan Sub-Group Report on exploration & production

The Xth Plan targets a domestic oil production of about 32 MMT by 2006/7, whereas the demand is expected to reach about 214 MMT. This gap of 85% is to be bridged by imports. Any shortfall from the ONGC target of oil production of about 25 MMT by 2006/7 will further increase the import dependence.

The oil production projections of ONGC also show stagnating and even declining trends till 2006/7, as shown in Table 1.2 below. However, in light of huge investment plans of ONGC for E&P activities and the Bombay High redevelopment, ONGC can be expected to make substantial improvements in current oil and gas production levels.

Gas production projections by ONGC are shown in table 1.2 and also present stagnating trends.

Table 1.2 Oil and gas production projections of ONGC

	2002-03	2003-04	2004-05	2005-06	2006-07
Oil (MMT)	25.897	25.995	26.382	26.189	25.562
Gas (MMCMD)[a]	50.48	48 88	46.05	46.51	47.04

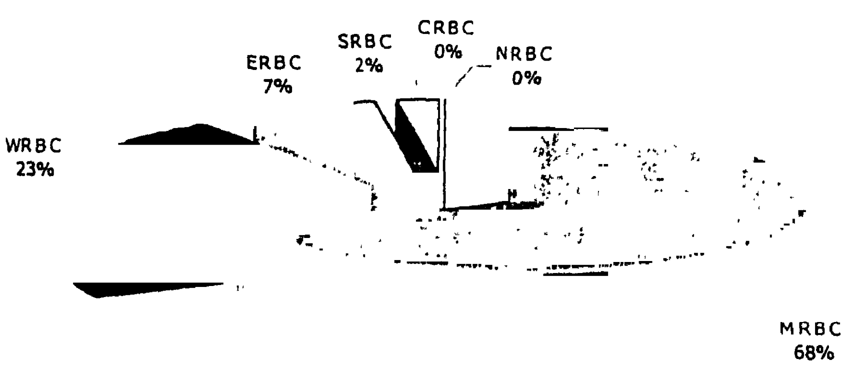
Source. ONGC

ONGC's exploration and production activities are spread over the following regions:

1. Mumbai – Bombay High fields
2. Western region – Gujarat and Cambay basin
3. Eastern region – Assam and Tripura fields
4. Southern region – Krishna Godavari and Cauvery basin
5. Central region – with headquarters at Kolkata

The maximum production is centred in the Bombay High region and accounts for around 68% of the total ONGC crude production.

Figure 1.3 Share of business centres



Crude oil production by ONGC from all regions is sweet crude with sulphur content being less than 0.5%. The Xth Plan projects that the demand for sweet crude in India will rise from about 28 MMT in 2002/3 to about 39 MMT in 2006/7. As such ONGC is not expected to face any demand crunch for its crude. However, uncertainty remains as to how to market this crude so as to obtain the

[a] Does not include production from joint venture fields

best prices. The same applies to natural gas as demand far exceeds domestic supply.

However in view of emerging surplus refining capacity in India, and surplus of many products in the country, offtake of value added products of ONGC may be uncertain. Bulk of the value added produce of ONGC includes naphtha and LPG. The Xth Plan projects a negative growth rate of naphtha demand by 3.5% till 2006/7, but expects the demand for LPG to grow substantially at the rate of 8.2%. In line with these projections, ONGC projects a decline in naphtha production from 1.5 MMT in 2002/3 to 1.16 MMT in 2006/7. But this will still result in substantial surplus in naphtha if the proposed refinery capacity expansions materialise. It also projects a fall in its LPG production from 1 MMT to 0.87 MMT in the same period. The year-wise naphtha and LPG production projections by ONGC are shown in Table 1.3 below.

Table 1.3 Production projections of Naphtha and LPG by ONGC (Million Tonnes)

	2002-03	2003-04	2004-05	2005-06	2006-07
Naphtha	1.482	1.290	1.189	1.171	1.160
LPG	1.013	1.002	0.936	0.899	0.873

Source. ONGC

Till now ONGC had been selling crude oil to refineries as directed by the Oil Co-ordination Committee (OCC). Sales of natural gas are through GAIL and allocations are made by the Government. For consumers taking gas directly from ONGC, the allocations are decided by the Gas Linkage Committee (GLC). Sales of LPG are also guided by OCC through the Oil Marketing Companies (OMCs) – IOC, HPCL and BPCL. Though naphtha is a decontrolled product and ONGC is free to market its naphtha, bulk of the naphtha is sold through the OMCs while ONGC undertakes some direct marketing also. With complete deregulation of the Indian oil industry, given that marketing is not the core area of ONGC, the organisation has to gear up to the competition and strategise its sales so as to obtain best deal for all its products.

Given this backdrop, this study focuses on developing a strategy for marketing crude oil, natural gas and value added products, premised on a changed scenario that will prevail in the post deregulation period.

Structure of the report

Part 1 of the report addresses marketing issues related to crude oil. In Chapter 2, the global oil scenario has been evaluated to establish the global crude oil reserves, major producers and consumers of crude oil, and the likely scenario that would prevail in the future. Chapter 3 presents a brief on oil prices followed by the likely demand supply scenario for crude oil envisaged for India in the next five years.
Chapter 4 details the international classification of crude oil and in this context the crudes that ONGC's oil could be benchmarked to are enumerated, along with the international markets for these benchmarks. This chapter also explores the export option for ONGC crudes.
Chapter 5 outlines the current demand for crude by Indian refineries, focusing on the demand for sweet crude, which ONGC could meet.
Chapter 6 examines the supply infrastructure for the Indian refineries including details such as ownership, to highlight the current linkages.
Chapter 7 provides the policy context within which crude sales are currently made in India.
In Chapter 8, a brief outline is provided on the methodology adopted for evaluating marketing options for ONGC's crude followed by details for Bombay High, North and South Gujarat, Cauvery basin crude, KG Basin crude and North East crude in Chapters 9, 10, 11, 12 and 13 respectively.

Part 2 of the report is focussed on Natural Gas. Chapter 14 begins with an analysis of the demand-supply situation for gas, projections of demand linked to the imputed value of gas, the likely LNG projects that would come up in the next five years and the impact that could have on pricing of gas. Finally the avenues open to ONGC for marketing its gas are considered and evaluated.

Part 3 of the report begins with Chapter 15 examining the case for LPG marketing and Chapter 16 deals with marketing options for Naphtha.

Part 4 of the report is concerned with the risk management issues in the volatile international crude oil market. Chapter 17 outlines the various considerations that assume importance in deciding on the hedging policy.

The main report ends with a summary of conclusions of all the aspects covered in the report in Chapter 18 and is followed by annexures for each chapter.

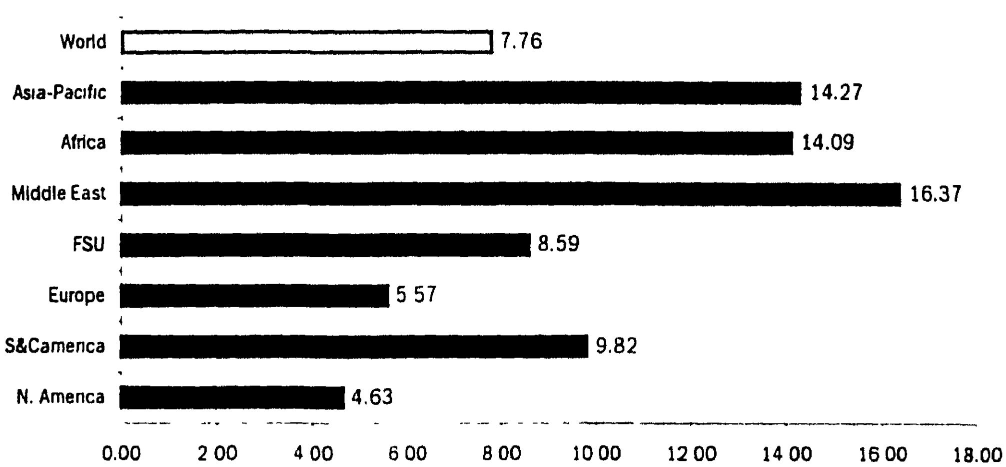
2 Global oil scenario

Primary energy consumption

Energy is a key driver of economic growth. The industrial nations are heavily dependent on energy for economic prosperity. The largest economies are the largest consumers of energy in the world. Historically, North America has been the single largest consumer of primary energy in the world followed by Europe and Asia-Pacific.

The following chart shows the rate of growth in energy consumption of major regions in the world over the period 1990-2000.

Figure 2.1 Rate of growth in energy consumption (%) - 1990 - 2000



Source. Own calculations from BP Historical Statistics

The developed regions like N. America and Europe have shown a slow rate of growth over the period while the developing regions like South and Central America, Africa, Middle East and Asia-Pacific have shown a high energy consumption growth rate, which is understandable given that former are mature economies. This has resulted in a shift in the weight of the regions in total energy consumption, as shown in the table below.

Table 2.1 Share of regions in total energy consumption (%)

Region	1990	2000
N. America	28.3	30.1
S&C America	3.4	4.2
Europe	22.1	20.8
FSU	17.7	10.5
Middle East	3.3	4.4
Africa	2.7	3.1
Asia-Pacific	22.5	26.9

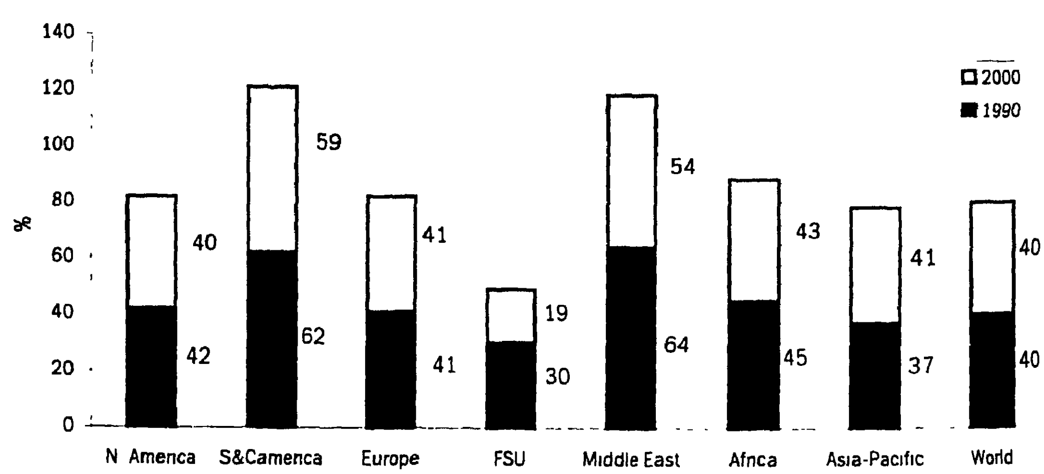
Source. Own calculations from BP Historical Statistics

North America has, however, maintained its overall leadership in energy consumption.

Importance of oil

The share of oil in primary energy consumption for the world as a whole has remained unchanged at 40% from 1990 to 2000. All the regions have experienced a decline in the share of oil with a sole exception being Asia-Pacific. The largest decline has occurred in Former Soviet Union (FSU) where the share of oil declined from 30% to 19% followed by Middle East where the share declined from 64% to 54%. Asia-Pacific, on the other hand, has seen an increase in the share of oil from 37% to 41%, as shown in the figure 2.2.

Figure 2.2 Share of oil in meeting energy requirement (%)



Source. Own calculations from BP Historical Statistics

But what is common among all regions is that the share of gas has risen, at the expense of oil and coal.

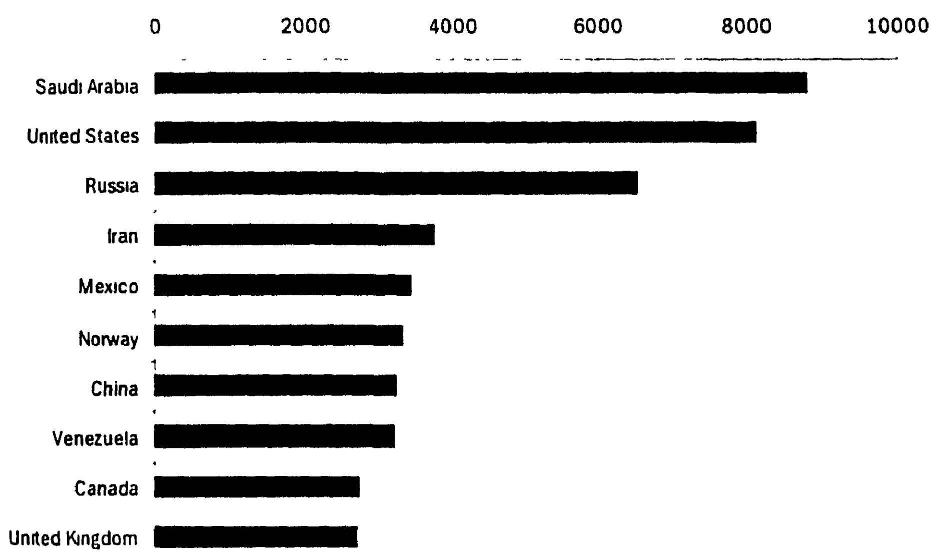
Global oil production and consumption

Current scenario

Production

Total proven reserves of world oil are 1046.4 thousand million barrels. Of this the Middle East Gulf countries have the largest share of about 65%. Accordingly, this region is an important producer and supplier of oil having the largest share of 31% in total oil production of 74.15 million barrels per day. Region-wise reserves and production of oil are listed in Annexure 2.1. At the current production levels these reserves are expected to last for 83 years.
The following figure shows the top ten countries with largest crude oil production for the year 2000.

Figure 2.3 Largest crude oil producing countries in the world ('000 bbls/day)



Source. World oil and gas review, 2001

As this chart shows, Saudi Arabia is the largest crude oil producing country followed closely by United States and Russia. More important is the fact that three out of these top ten countries are members of OPEC[a] and in fact, seven out of the top ten countries with largest crude oil reserves are also members of OPEC.

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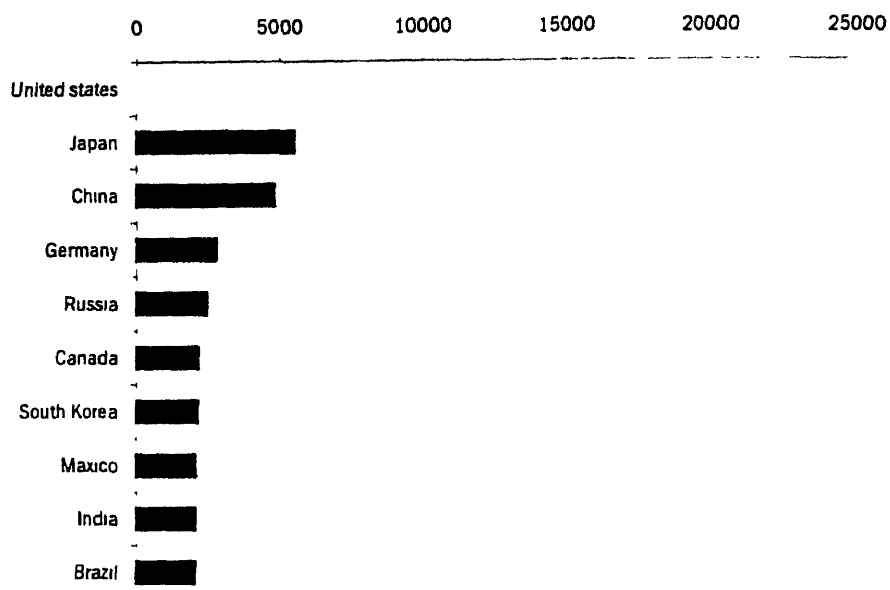
[a] OPEC members are – Saudi Arabia, Iran, Kuwait, UAE, Qatar, Algeria, Libya, Nigeria, Indonesia, Venezuela and Iraq.

Consumption

The following figure shows the top ten countries with largest crude oil consumption.

Figure 2.4 Largest crude oil consuming countries in the world ('000 bbls/day)



Source. World oil and gas review, 2001

As this chart shows, only five of the top ten countries in this list are also among the top ten countries with largest production. This is also manifested in the fact that crude oil is one of the most actively traded commodities in the world. This also shows the strategic importance of oil for major consuming countries. Countries like United States, Japan, Germany and India are heavily dependent on oil imports to meet their oil requirement.

The major producers and consumers of crude oil are listed in Annexure 2.2.

Future outlook

According to International Energy Outlook (IEO) 2002, published by USDOE, oil production is projected to increase to 87.9 million bbls per day by 2005 and to 97.4 million bbls per day by 2010. This implies an annual growth rate of 4% from 2000 to 2005. Likewise, consumption is projected to grow from 84.9 million bbls per day by 2005 to 94.9 million bbls per day by 2010. The detailed projections are shown in Annexure 2.3.

As per the projections, the ten largest producers of crude oil are projected to be

as follows –

Table 2.2 Projected largest crude oil producing countries (million bbls/day)

	2005	2010
Saudi Arabia	12.6	14.7
FSU	9.6	11.9
United States	9	8.7
North Sea	6.6	6.5
Venezuela	4.2	4.6
C&S America	4.2	4.8
Mexico	4.1	4.2
Iran	4	4.3
Iraq	3.1	3.8
China	3.1	3.1

Source. International Energy Outlook, 2002, USDOE

Comparison of this table with figure 2.3 shows the Saudi Arabia will maintain its position at the top of the table whereas Former Soviet Union will move ahead to second spot. Noticeable is the decline of Iran and rise in North Sea and Venezuela. This is perhaps due to the lack of foreign investments in the Iran's oil sector that will hamper the country's crude oil production.

The following table shows the ten biggest consuming countries in the world.

Table 2.3 Projected largest crude oil consuming countries (million bbls/day)

	2005	2010
United States	21.2	22.7
Japan	5.7	5.8
China	5.3	6.7
Former Soviet Union	4.9	5.6
Germany	3	3.1
India	2.6	3.4
South Korea	2.5	2.8
Mexico	2.3	2.8
Brazil	2.3	2.9
Canada	2.1	2.1

Source. International Energy Outlook, 2002, USDOE

Comparison of this table with the figure 2.4 shows that India is likely to become the sixth largest energy consumer in the world from the current level of tenth. Otherwise, the ten largest consuming countries will remain so for the coming decade.

Oil trade

Current scenario

Crude oil is the world's most actively traded physical commodity; the largest markets being in London (International Petroleum Exchange), New York (New York Mercantile Exchange) and Singapore (Singapore Mercantile Exchange). The table below shows the trade movements in the year 2001.

Table 2.4 Oil trade movements[b], 2001 (million tonnes)

From	To												
	USA	Canada	Mexico	South and Central America	Europe	Africa	Australasia	China	Japan	Other Asia Pacific	Rest of World	Unidentified	Total
USA	-	6.3	12 1	7 9	11 1	0 2	0 3	0 3	0 6	3 9	0 9		
Canada	88.0	-	-	0 2	0 5	-	-	-		0 2	-		
Mexico	70.8	1.3	-	9.2	9 8	0 2	-		1 1	1 0	0 2		
S. & Cent America	126.3	6.0	1 5	-	13 8	0 6	-	0 3	0 4	5 6			
Europe	46 2	28.9	0.3	2.2	-	7 1	-	1 1	0 1	5 2	4 2		
Former Soviet Union	4.3	-	-	7 1	181 2	0 5		5 3	0 7	8 7	2 3	20 0	
Middle East	138.0	7.2	1 1	11 8	176 2	41 0	9.1	34 2	208 8	316 7	2 5	-	
North Africa	13.7	3.6	0.8	4 3	96.9	3.9	-	0 3	0 5	7 0	3 2		
West Africa	68.1	1.0	-	11 3	34 9	1 5		3 8	0 8	36 9			
East & Southern Africa	-	-	-	-	-	-		5 0	1 4	0 9	-		
Australasia	2.2	-	-	-	-	-		1 0	3 9	14 1		-	
China	1.1	-	-	0 3	0 2	-	0 3		4 2	8 4			
Japan	0.4	-	-	-	0 1	0 2	0 2	1 1		2 5			
Other Asia Pacific	9 4	0.2	0.2	-	2 3	0.3	19 4	27 2	34 2	10 8	0 8		
Unidentified *	5.2	2.3	-	-	42 9	-	1 2	8 7	0 5	1.1			
TOTAL IMPORTS	573.7	56.8	16.0	54 3	569 9	55.5	30 5	88 3	257 2	423 0	14 1	20 0	

Source: BP Statistical Review of World Energy, 2002

Of total oil exports in the world, the largest share (44%) was from the Middle East region followed by Africa (14%). Major oil reserves in the world are in the Middle East countries whereas consumption within these countries is comparatively much less resulting in availability of huge crude oil surplus in this region. Major consumption centres of oil from the Middle East Gulf are in USA followed by Asia and Europe. USA is the largest net importer of oil, and Saudi Arabia the biggest exporter. Country-wise oil exports and imports from 1995-2001 have been illustrated in Annexure 2.4.

Sweet vs sour

The major sweet crude producing regions are Asia-Pacific, Africa and Europe whereas Middle East largely produces sour crude. The African crude is primarily

[b] This table shows the trade pattern for both crude oil and petroleum products. However, petroleum products constitute only 22% of the total trade.

consumed in North America and Europe while the Asia-Pacific crude is primarily consumed within Asia-Pacific with Japan and China being the major consuming countries. The details of sweet crude demand-supply and markets are discussed in Chapter 4.

Future outlook

From Annexure 2.3, it can be assessed that Middle East countries will have an increasing oil surplus and hence will continue to contribute significantly to world exports. Also the Asia-Pacific region shows an increasing consumption-production gap or consumption deficit. Hence this region can be expected to command the largest import flows. Table 2.5 below shows the projected oil deficit/surplus.

Table 2.5 Net oil deficit/surplus (mb/d)

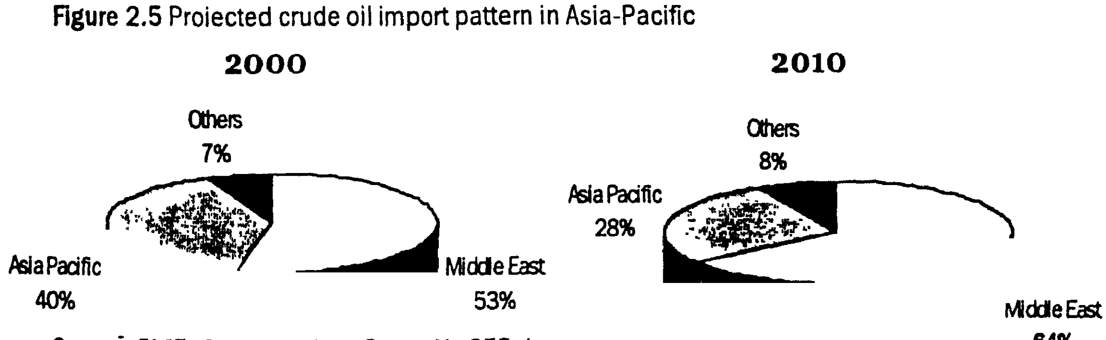
	2005	2010	2015	2020
North America	-9.5	-11.5	-13.1	-15
Middle East	22.6	26	31.2	36.6
South and Central America	3.1	3	2.8	3.1
Europe	-8.6	-9.1	-9.7	-10
Asia-Pacific	-15.8	-19.8	-24.7	-29.6
Former Soviet Union	4.7	6.3	6.7	7
Africa	6.5	7.6	9.1	10.8
World	3	2.5	2.3	2.9

Source. International Energy Outlook, 2002, USDOE

Trade in Asia-Pacific

According to FACTS, stagnated oil production in Asia and increasing oil use is reflected in growing imports. About 60% of crude oil imports by Asia-Pacific countries in 2000 came from sources outside the region and this is expected to rise to 72% in 2010. Middle East is the main exporter to Asia-Pacific countries. The share of the region's crude imports from Middle East is expected to increase from 53% in 2000 to 65% in 2010.

Figure 2.5 Projected crude oil import pattern in Asia-Pacific



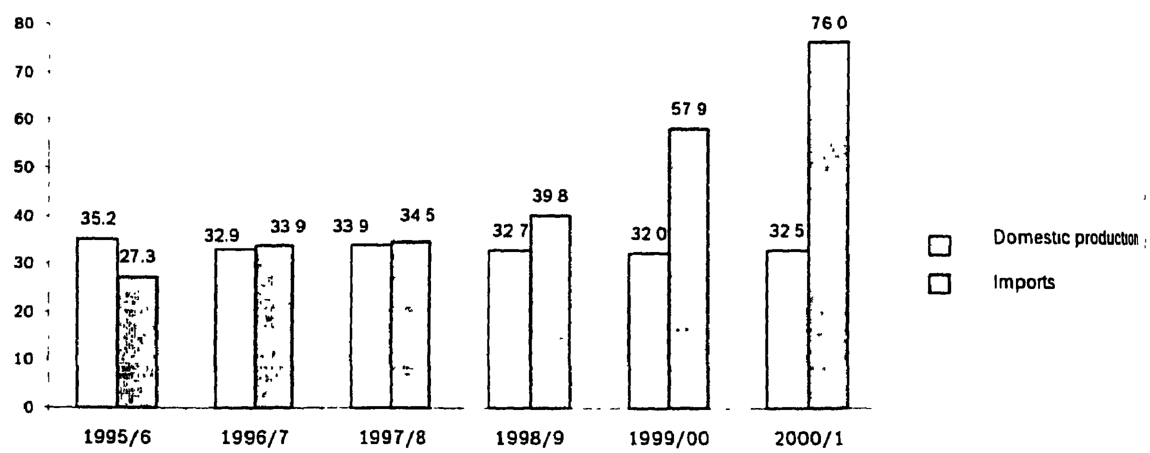
Source: FACTS Energy Advisory Report No.255, June

The major crude exporters in the region are Indonesia, Malaysia and Vietnam. Vietnam exports over 99% of its crude oil. Though Australia shows a negative exportable surplus, it trades certain crude oils like the Thvenard Island and Jabiru. China used to be the second largest crude exporter in the region during the mid 1980's. However today it is a huge importer of crude oil and at present imports about 1.4 million barrels/day (FACTS Inc, Energy Advisory Report No 255, June 2001).

Trade in India

India is largely dependent on imported crude oils and imports show an increasing trend over the years as is evident from Figure 2.6.

Figure 2.6 Trend in domestic crude oil production and imports (MMT)



Source: CMIE

The Tenth Plan projects oil imports by India to increase to about 147 MMTPA by 2006/7. Like most of the oil importing countries in the world, India sources most of its crude oil from the Middle East countries followed by African countries. Crude oil imports by India and requirement of Indian refineries are discussed in details in Chapter 5.

3 Oil markets and prices

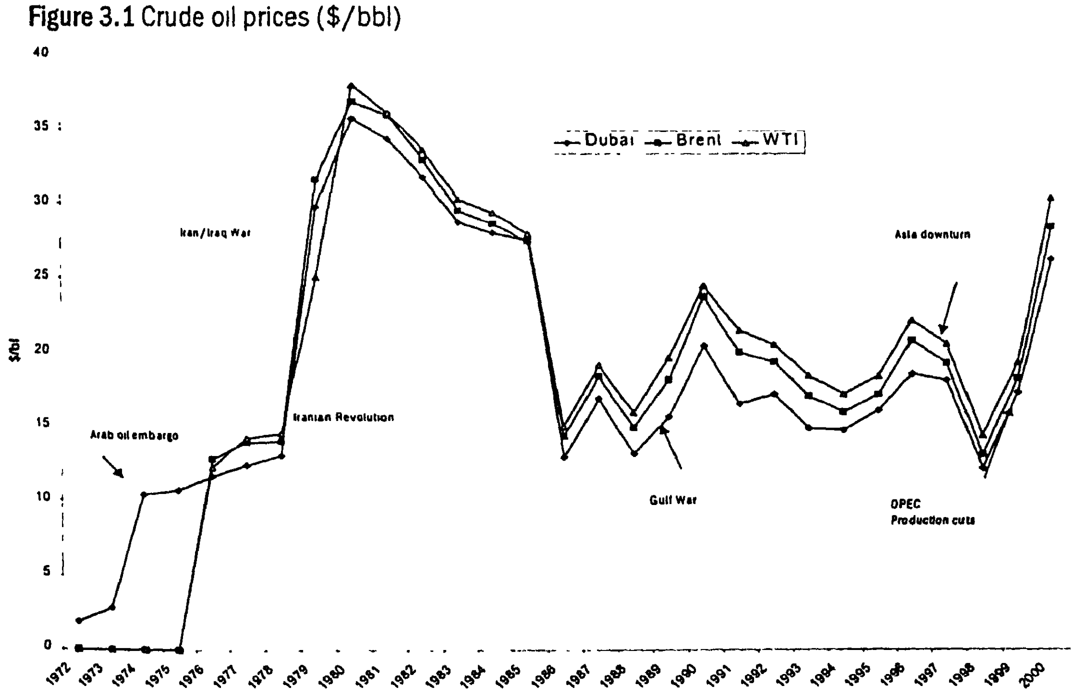
International oil prices

Akin to other commodities, the price of crude oil is closely linked to demand and supply situation. As demand and supply of oil are vulnerable to various factors – political forces, unforeseen events like wars or natural calamities, climate or manipulations by large oil producers, oil prices tend to be highly volatile.

OPEC countries command about 44% of world oil production. Moreover, over the years OPEC has become a cohesive group of producing countries whose commercial interests anciently do not conflict and therefore OPEC has been recently able to regulate the production of oil successfully. As price of any commodity is fundamentally governed by the forces of demand and supply, the cap on oil supply has triggered an upward pressure on the price of this commodity. Therefore market forces do not strictly govern the oil prices at present.

Figure 3.1 below illustrates how world events have affected oil prices in the over the years.

Figure 3.1 Crude oil prices ($/bbl)



Recent price trends

In 1997, the financial crisis and economic slowdown in Asia led to a slackening of oil demand that sent oil prices crashing to $ 10/bbl in1998-99. Consequently from March 1999 onwards OPEC decided to cut production and in effect removed about 5 million bbl/day from the market. This accompanied with falling inventories, led to price recovery of more than $ 30/bbl. OPEC once again increased production in March 2000, resulting in lowering prices to $ 21/bbl.

During the March 2000 meetings, OPEC adopted a target range for the OPEC basket price of oil between $22 and $28 per barrel. As per the mechanism adopted to maintain the price band, it was decided that prices above the range, sustained for 20 trading days, would result in increases in production of 500,000 b/d and prices below the target range for 10 trading days would result in cuts in production of 500,000 b/d.

However the oil prices had reached a high level of $33 a barrel last year, but have been softening this year. So much so that OPEC decided in July to cut production by a million barrels a day with effect from September 1, 2001. The EIA had also reported that the market would be more or less stable for the rest of the year. The attacks on the US on September 11 took place in this background. Immediately the oil price went up by $2 /bbl. This was caused by traders anticipating an immediate retaliation by the US. However, the retaliation did not come and the price started moving down within two days. OPEC has decided to maintain the production level. On October 5, the price of the OPEC basket of crude oils stayed below $22 a barrel for 10 consecutive days. Normally, this would bring an automatic cut of 500,000 barrels a day in OPEC production. There has been no move so far toward production cuts.

Presently, the prices are in the range of $22 - $25 per barrel and OPEC has not proposed to increase the production in order to soften the prices saying that currently prices do not indicate an alarming situation in demand and supply forces. Many analysts have predicted that increases in supply will not come before third quarter of 2002 when the winter demand sets in.

Oil markets

The decade of 1970 was an important phase in the development of international oil market. This decade was marked by the de-integration of the oil industry because of the nationalisation of the assets of the big multinationals in the OPEC and some other third world oil producing countries. As a result, the major companies lost privileged access to the equity oil for their refineries. A two-part

structure was born in which the producing countries became seller of crude oil rather than the passive tax recipient and the oil majors became buyers of crude oil rather than the taxpayers.

Emergence of trading instruments

With this emergence of bi-polar market for oil in which OPEC and non-OPEC markets were often pulling the prices in different directions, the price risk rose. The crude oil purchased in OPEC region on OPEC fob often proved to be too expensive compared to equivalent non-OPEC crude when it reached the final destination. Occasional changes in the administered price highlighted the need to hedge the sales as well as purchases. Slowly, the spot market started to grow at an accelerated pace, largely because of the trading between the holders of the term contracts who were then able to match and balance their crude oil requirement. Instruments new to the oil market like forwards, futures and swap deals followed this.

The two major trading exchanges are the NYMEX (New York Mercantile Exchange) and the IPE London (International Petroleum Exchange). These markets use a variety of information from various sources to fix the crude oil prices in the forwards and futures markets which forms the base for prices in the spot markets.

Marker crude oils

Brent as world marker

As there are a large number of crude oils with varying properties, buyers and sellers find it convenient to refer to a few crudes as benchmark. Prices of other crudes are accordingly indexed to these marker crudes at a discount and premium. The major benchmark crudes are Brent from UK, West Texas Intermediate (WTI) from USA, Dubai from Dubai and Tapis from Malaysia. Spot trade is also carried out as differentials against official selling prices (OSPs) as quoted by some countries in the Middle East and Far East.

Brent has generally been accepted as the world's benchmark crude although sales volume of this crude maybe less than some of the other crudes particularly those from Saudi Arabia. According to the International Petroleum Exchange (IPE), Brent is used to benchmark two-thirds of total crude oil traded in the world. Most of the trade in North Sea, West Africa and Mediterranean regions is carried out against dated Brent.

Recently, however, questions have been raised pertaining to the reliability of Brent as a benchmark[a]. Many organizations like Platts' have proposed various ways to make Brent more indicative. According to Platts', the core problem is the dwindling output that makes it prone to squeezes. Its has thus suggested injecting volume by accepting, for assessment purposes, North Sea Oseberg and Forties as substitutes for Brent. This however disregards the physical nature of the industry. Assessing a benchmark that can flip between any of three grades is highly subjective. Seller's freedom to supply any grade opens fresh opportunities for manipulation. Moreover, this methodology is highly subjective as Platts' will decide which crude out of the named three best represents the market. BP suggests that a well-defined index may be preferable to Platts' proposal of an unclear approach based on three crudes. Alternatively, BP suggests that dated Brent could be dropped as a marker and companies could trade physical oil at a differential to a revised forward market.

US marker crude

West Texas Intermediate (WTI) is the benchmark crude for sales of crude oil in the US. The prices of crude oil sold in the US are in relation to prices of WTI. However, though majority of the exports from West Africa goes to the USA, trade against WTI (from Africa) is not large and much of the trade with WTI as marker takes place in the US Gulf Coast (USGC). For example, price of Qua Iboe from Nigeria landing at USGC is differenced against WTI.

Middle East Gulf marker crude

Middle East exports approximately 45% crude oil to various countries in the world. The economy in these countries is dominated by the oil sector. Traditionally the national oil companies who are working directly under the regime of the ruling monarchy control the entire oil sector. These companies have been marketing their crude oil based on their official selling price (OSP) without negotiations.

The important features of this pricing policy are as follows:

1. Crude oil is normally marketed on an annual basis through term contract at the official selling prices.
2. The OSPs relate to the daily market price of some other marker crude oil traded in the market.
3. The OSPs contain the following elements:

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[a] Petroleum Argus Global Markets – various editions

(i) price linkage
(ii) price out period
(iii) publication – e.g. Platt crude oil market wire etc.
(iv) premium/discount (this indicate the quality difference of the crude oil vis-à-vis marker crude oil and the demand-supply situation of the crude oil)

4. Since these countries market their crudes to different regions of the world therefore they have different official selling price for different markets.
5. The OSPs of Saudi Arabia, Kuwait and Iraq are evaluated under three names, namely US Market, European Market and East of Suez Market.
6. The marker crudes for these markets are as follows:
   (i) US Market – WTI
   (ii) European Market – Brent blend
   (iii) East of Suez Market – average of Oman and Dubai Crude oils
7. The National Oil Company declares the official selling price every month (i.e. the applicable premium/discount) for a particular month of loading.

The prices applicable to the east of Suez market

Saudi Arabia, Kuwait and Iran use the monthly average of Oman and Dubai as published in Platt's crude oil market wire for the month of loading plus/minus the premium/discount.

Iraq uses the average of Oman and Dubai crude oil published in Platts' crude oil market wire for the ten quotations starting from the date of bill of lading. The premium/discount is revised every month.

UAE announces a fixed price for crude oils marketed by it. However, the price arrived at is based on the price of Dubai crude oil with suitable adjustment for quality, market condition etc. The price is announced after completion of the month in the first week of the following month.

Oman and Qatar also follow this methodology of UAE for declaring OSPs.

Trade from the Mideast Gulf is also carried out against OPEC Basket. OPEC is an organisation consisting of all major oil producing countries. These countries have their own benchmark crude called OPEC basket. OPEC basket price is the average price of the following seven crude oils:

(1) Saudi Arabia's Arab Light
(2) UAE's Dubai
(3) Nigeria's Bonny Light
(4) Algeria's Saharan Blend
(5) Indonesia's Minas

(6) Venezuela's Tia Juana Light

(7) Mexico's Isthmus

OPEC members produce six of these crudes while Mexico, who is not a member of the OPEC cartel, produces Isthmus. The following table shows the pricing formulae for various crudes for various markets.

Table 3.1 Pricing formulae for Asia market

Grade of crude - API	Point of sale	Price formula	Adjustment Factor 00/99
For Asian Market			
Saudi Arabia			
Arabian Light - 33	Fob	(Dubai + Oman)/2 +- (Adjustment factor)	0.1
Arabian Heavy - 27	Fob	(Dubai + Oman)/2 +- (Adjustment factor)	-1.5
Iran			
Iranian Light - 33	Fob	(Dubai + Oman)/2 +- (Adjustment factor)	0
Iranian Heavy- 30	Fob	(Dubai + Oman)/2 +- (Adjustment factor)	-0.65
Kuwait			
Kuwait - 31	Fob	(Dubai + Oman)/2 +- (Adjustment factor)	-0.95
Neutral Zone			
Khafji – 28	Fob	(Dubai + Oman)/2 +- (Adjustment factor)	-1.5
Qatar			
Dukhan - 41	Fob	(Oman MPM) +- (Adjustment factor)	0.75
Marine - 36	Fob	(Oman MPM) +- (Adjustment factor)	0.27
Iraq			
Basrah - 34	Fob	(Dubai + Oman)/2 +- (Adjustment factor)	-1.1
Yemen			
Marib – 48	Fob	(Dated Brent) +- (Adjustment factor)	-0.5
Masila - 30.5	Fob	(Dated Brent) +- (Adjustment factor)	-1.2
Mexico			
Isthmus - 33	Fob	(Dubai + Oman)/2 +- (Adjustment factor)	0.1
Maya – 32	Fob	(Dubai + Oman)/2 +- (Adjustment factor)	-2.65

Table 3.2 Pricing formulae for US market

Grade of crude - API	Point of sale	Price formula	Adjustment Fact 00/9
For US Market			
Saudi Arabia			
Arabian Light - 33	Fob	(WTI) +- (Adjustment factor) - (Freight discount)	-4.65
Arabian Heavy - 27	Fob	(WTI) +- (Adjustment factor) - (Freight discount)	-6.35
Kuwait			
Kuwait - 32	US Gulf	(WTI) +- (Adjustment factor)	-4.6
Iraq			
Basrah - 34	Fob	(WTI) +- (Adjustment factor)	-6.7
Kirkuk - 37	Ceyhan	(WTI) +- (Adjustment factor)	-5.5

Grade of crude - API	Point of sale	Price formula	Adjustment Factor
Nigeria			
Bonny Light - 36	Fob	(Dated Brent) +- (Adjustment factor)	0.2
Forcados - 29	Fob	(Dated Brent) +- (Adjustment factor)	-0.4
Brass River - 42	Fob	(Dated Brent) +- (Adjustment factor)	0.15
Mexico			
Isthmus - 33	Fob	0.4 x (WTS + LLS) + 0.2 x (Dated Brent) +- (Adjust. Factor)	-1.5
Maya - 32	Fob	0.4 x (WTS + 3% Fuel Oil) + 0.1 x (LLS + Dated Brent) +- (Adjust. Factor)	-2.55
Olmeca - 39	Fob	(WTS + LLS + Dated Brent)/3 +- (Adjustment factor)	0.05
Colombia			
Cano Limon - 30	Fob	(WTI) +- (Adjustment factor)	-4.52
Venezuela			
Furrial - 30	Fob	(WTI) +- (Adjustment factor)	-4.72

Table 3.3 Pricing formulae for West European market

Grade of crude - API	Point of sale	Price formula	Adjustment Factor 00/9
For West European Market			
Saudi Arabia			
Arabian Light - 33	Fob	(BWAVE) +- (Adjustment factor) - (Freight discount)	-3.95
Arabian Heavy - 27	Fob	(BWAVE) +- (Adjustment factor) - (Freight discount)	-6.2
Kuwait			
Kuwait - 31	Fob	(BWAVE) +- (Adjustment factor)	-5.1
Iran			
Iranian Light - 33	Rotterdam	(Dated Brent) +- (Adjustment factor)	-0.84
Iranian Heavy - 30	Rotterdam	(Dated Brent) +- (Adjustment factor)	-1.34
Iraq			
Kirkuk - 37	Ceyhan	(Dated Brent) +- (Adjustment factor)	-3.5
Yemen			
Marib - 48	Fob	(Dated Brent) +- (Adjustment factor)	-0.5
Masila - 30.5	Fob	(Dated Brent) +- (Adjustment factor)	-1.2
Nigeria			
Bonny Light - 36	Fob	(Dated Brent) +- (Adjustment factor)	0.02
Forcados - 29	Fob	(Dated Brent) +- (Adjustment factor)	-0.4
Brass River - 42	Fob	(Dated Brent) +- (Adjustment factor)	0.15
Libya			
Es Sider - 37	Fob	(Dated Brent) +- (Adjustment factor)	-0.8
Zueitina - 42	Fob	(Dated Brent) +- (Adjustment factor)	-0.6
Syria			
Syria Light - 37	Fob	(Dated Brent) +- (Adjustment factor)	-2.5
Souedieh - 24	Fob	(Dated Brent) +- (Adjustment factor)	-6
Egypt			
Suez Blend - 32	Fob	(Dated Brent) +- (Adjustment factor)	-4
Belayim Blend - 26	Fob	(Dated Brent) +- (Adjustment factor)	-5.3

Grade of crude - API	Point of sale	Pnce formula	Adjustment 00/9
Mexico			
Isthmus - 33	Fob	0.887 x (Dated Brent) + 0.113 x (3.5% Fuel Oil) - 0.16 x (1% F.O. - 3.5% F.O.) +- (Adjust. Factor)	-0.11
Maya - 32	Fob	0.527 x (Dated Brent) + 0.467 x (3.5% Fuel Oil) - 0.25 x (1% F.o. - 3.5% F.O.) +- (Adjust. Factor)	-1.1

Source. IEEJ, July 2001

WTI: West Texas Intermidiate; LLS: Louisiana Light Sweet; WTS: West Texas Sour; Oman MPM Posted pnce of Oman crude; BWAVE: IPE Brent Weighted Average.

Note: "The Adjustment Factor" in the pnce formula for Saudi Arabian crude directed to the US/European market include the "Freight discount factor".

Price forecasts

Crude price forecast is an extremely difficult exercise as the prices are governed by a number of unreported events and other factors like demand and supply etc. Nevertheless several agencies are engaged in price forecasting exercises and some forecasts are presented as follows.

The Madison Energy Advisors' oil price forecasts, as quoted in the Oil and Gas Journal (Feb 12, 2001), suggested a consensus that WTI prices will retreat somewhat from the 2000 levels.

Table 3.4 Madison Energy Advisors forecasts ($/bbl)

	Houston Energy Banks*	Active middle market*
2001	24.02	26.51
2002	20.87	24.78
2003	20.73	23.95
2004	21.10	24.27
2005	21.48	24.77

*The forecasts are based on a poll of Houston Energy banks and by companies active in the middle range of acquinng and divesting producing oil and gas properties.

The UK based Centre for Global Energy Studies forecasted a price range of $ 19-$ 35/bbl in the first quarter of 2002. While the higher end of the range coincides with a scenario of the cuts announced in March and less Iraqi oil entering the market, there is a feeling in the market that production cuts won't be observed by the members and non-members in their entirety. The lower end of the forecast is based on low demand scenario accompanied by no cuts by OPEC.

The Energy Information Administration (US Department of Energy) indicate that the average world oil price will increase from $17.35 per barrel in 1999 (1999 dollars), to $27.60 per barrel in 2000, falling to about $20.50 per barrel by 2003. In 2020, the price reaches $22.41 per barrel. The firmness of prices over the next several years in this study by EIA is attributed to production

cutbacks by OPEC and several non-OPEC nations, a lag in the response of non-OPEC producers to price increases, and renewed demand growth in Asia.

The price that ONGC could get in international markets would be closely linked to the international crudes it is benchmarked to, the demand for ONGC crude as also the markets for which ONGC would compete. Chapter 4 thus seeks to identify the international markets for ONGC crudes by analysing the global demand and supply centres for sweet crudes based on projections of International Energy Outlook, 2002 published by Department of Energy, United States of America.

4 International markets for ONGC crudes

Oil producing regions

Crude oil comes in different varieties and qualities depending mainly on its specific gravity and sulphur content which in turn depend on the region from where the oil has been explored and pumped. Sweet crude can be defined as oil having sulphur content less than 0.5%, whereas crude containing more than 0.5% sulphur is categorised as sour. World Energy Council classifies oil as heavy if its API gravity is $<22.3^0$. Oil with API$<10^0$ are often categorised as bitumen or extra-heavy oil.

Basic properties of major crude oils in the world is discussed below. The world can be divided into 5 major oil producing regions – The Middle East Gulf, Africa, North Sea Europe, United States and Canada, Former Soviet Union and the Far East.

Middle East Gulf

The Gulf region is the major oil producing and exporting region in the world. The Middle East contributes to about 45% of world oil exports. Crude oils from this part of the world have relatively high sulphur content but they are mostly light. Marib Light from Yemen is by far the best quality crude in this region. It is not only a light crude but sweeter than most crudes from this part of the world. The detailed list outlining the characteristics of major crudes from this region is presented in Annexure 4.1.

Africa

Most of the production from the African continent comes from Nigeria followed by Libya, Algeria, Egypt and Angola. West African grades are typically sweet, with medium to light gravity. Major crudes from Africa are listed in the Annexure 4.2

North Sea

Norway and United Kingdom hold the majority of the North Sea's oil reserves. The most important crude from this region is the Brent blend. It is a mixture of oil streams collected from two distinct pipeline systems – the Brent and the

Ninian systems. Brent blend can be characterised as light, sweet crude oil. Horsnell and Mabro[a] provides that, during 1980-1992, the gravity of its constituent parts varied from 30-31° API (the Hutton and Osprey fields) to 39-40° (the Brent, Alwyn North, Don and Staffa fields). Sulphur content varied from 0.2% by volume for the Brent and Alwyn North fields up to 1% for the Tern field. The incremental developments of the Brent system produced oil that was much heavier and had higher sulphur content than the existing fields. By contrast, the quality of the Ninian stream improved significantly over time, became lighter than the Brent stream in 1988. As per reference texts, the gravity of Brent blend is normally taken to be around 38° API.

API and sulphur of important crudes from this region is provided in Annexure 4.3.

United States of America and Canada

The West Texas Intermediate (WTI) and Alaskan North Slope (ANS) are the most important crude oils from the USA. WTI is a light sweet crude whereas ANS is a medium heavy, sour oil. Canada has the largest heavy oil resource in the world followed by Venezuela. Oil from Canada is also very sour. Canada's heavy oil and bitumen is situated in the Athabasca, Wabasca, Peace River and Cold Lake areas of Alberta and in the Lloydminster area of Saskatchewan. Venezuela has extra-heavy oil in the 400 mile long Orinoco belt, in the east of the country. Alaska and Mexico also have large reserves of heavy oil. Major oils from America and Canada are listed in Annexure 4.4.

Former Soviet Union

Crude oils from the Soviet Union (former) range from being light-sweet in one region to heavy-sour in some other region and cannot be typecast into any single category. The API and sulphur content of some crude oils from Russia have been illustrated in Annexure 4.5.

Asia and the Far East

The Far Eastern crude oil is comprised primarily of Indonesian and Malaysian grades with some oil from Australia, China and Vietnam regions. The Asia-Pacific region is both importer as well as exporter of crude but it is overall a net importer. The detailed list is given in Annexure 4.6.

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[a] "Oil markets and prices" - Oxford Institute for Energy Studies

Though there are wide disparities in the quality of the crude produced in the world, the regions can be broadly classified according to the quality of crude they produce as presented in table below. The detailed classification of crudes is given in Annexure 4.7.

Table 4.1 Classification of regional crudes

Region	Type of crude
North America	Sour
S & C America	Sour
Europe	Sweet
Former Soviet Union	Sweet
Middle East	Sour
Africa	Sweet
Asia-Pacific	Sweet

Benchmark for ONGC crudes

All ONGC crudes are sweet but they differ in gravity. Following are the broad characteristics of the crudes produced by ONGC from different fields.

Table 4.2 Characteristics of ONGC crudes

Crude	API	Sulphur
Bombay High	39.50	0.140
KG Basin	41.75	0.021
Cauvery Basin	40.60	0.040
South Gujarat	45.81	0.016
North Gujarat	25.68	0.096
Jorhat Assam	27.20	0.080
Moran Assam	34.77	0.080

Source. ONGC

Response from ONGC and refineries has yielded the following benchmarks for the ONGC crudes.

Table 4.3 Benchmarked crudes

ONGC crude	Benchmarked crude (share in the mix) (Country of origin)
Bombay High	Bonny Light (50%) (Nigeria) : Escravos (50%) (Nigeria)
Krishna-Godavari	Arab Light (Saudi Arabia)
Cauvery Basin	Arab Light (Saudi Arabia)
South Gujarat	Bonny Light (Nigeria)
North Gujarat	Bonny Light (Nigeria)
Jorhat Assam	Bonny Light (Nigeria)
Moran Assam	Bonny Light (Nigeria)

Given that all ONGC crudes are sweet crudes, the following sections analyse the demand-supply and markets of sweet crudes in the world, identifies

international demand for ONGC crudes and analyses the export potential of ONGC crudes.

Demand/supply of imported sweet crude

The following table shows the historical as well as projected consumption of crude oil by major regions of the world. The historical figures are from BP-Amoco Statistical Review of World Energy while the projected figures are from International Energy Outlook (IEO) 2002, Reference Case, published by Department of Energy, USA.

Table 4.4 Consumption by major regions (million tonnes)

Regions	1995	2000	2005	2010
North America	955	1065	1275	1374
Europe	723	753	812	832
Middle East	190	209	279	339
South and Central America	194	219	264	319
Africa	104	117	169	199
Former Soviet Union	217	173	244	279
Asia-Pacific	851	969	1185	1384
World	3235	3504	4228	4726

Source. BP Statistical Review of World Energy, 2001; International Energy Outlook, 2002, USDOE

The following table shows the historical and projected production figures for the major regions of the world[b].

Table 4.5 Production by regions (million tonnes)

Regions	1995	2000	2005	2010
North America	647	652	802	802
Europe	311	329	383	378
Middle East	967	1112	1404	1633
South and Central America	294	348	418	468
Africa	341	373	493	578
Former Soviet Union	358	394	478	593
Asia-Pacific	350	381	324	324
World	3269	3590	4302	4775

Source. BP Statistical Review of World Energy, 2001; International Energy Outlook, 2002, USDOE

Combining the above two tables, we have the following net surplus/deficit status as follows-

[b] The projections for production are production capacity as projected for the future since it is not possible to assign the production projection figures to various regions from the document. Moreover, it is the production capacity which is more relevant since production can be raised in the event of a shortfall. In this sense, the deficit/surplus situation represents the maximum deficit/surplus expected. Moreover, since the projected production is 97% of the production capacity, these figures are not far off the mark.

Table 4.6 Net Surplus(+)/Deficit (-) (million tonnes)

Regions	1995	2000	2005	2010
North America	-309	-413	-473	-573
Europe	-412	-424	-428	-453
Middle East	777	903	1125	1295
South and Central America	100	130	154	149
Africa	237	257	324	378
Former Soviet Union	141	221	234	314
Asia-Pacific	-501	-588	-861	-1061
World	34	86	75	50

Source. Own calculations from BP Statistical Review of World Energy, 2001; International Energy Outlook, 2002, USDOE

As this table shows, North America, Europe and Asia-Pacific are projected to be net importers of crude oil while Middle East, Former Soviet Union, Africa and South and Central America are projected to be net exporters.

Assuming that the share of sweet crude in total imports remains the same[c], we can identify the demand for imported sweet crude of North America, Europe and Asia-Pacific regions. Africa and South & Central America, though surplus in crude oil, import some quantity if sweet crude. Assuming that the share of imported sweet crude will remain the same in total consumption of the countries, we can estimate the demand for imported sweet crude for these regions.

The following table shows the resulting demand for imported sweet crude for various regions.

Table 4.7 Demand for imported sweet crude (million tonnes)

Regions	2005	2010
North America	168	204
Europe	233	246
Asia-Pacific	117	144
Africa	13	15
South and Central America	21	25
Total	552	635

Source. Own calculations from International Energy Outlook, 2002, USDOE

Table 4.7 also shows the regions that have an exportable surplus of crude. Using the classification given in table 4.1, we can project the supply of sweet crude as follows:

[c] This can be defended on the ground that sweet crudes are priced at a premium to the sour crudes and hence any country will like to keep the percentage of the sweet crude as low as possible. Moreover, improvements in the refinery complexity will give the country more options as far as sweet and sour crudes are concerned.

Table 4.8 Exportable surplus of sweet crude (million tonnes)

Regions	2005	2010
Africa	324	378
Former Soviet Union	234	314
Total	558	692

Source. Own calculations from International Energy Outlook, 2002, USDOE

The following table shows the resulting demand supply balance of sweet crude for the coming decade.

Table 4.9 Demand-supply outlook for sweet crude (million tonnes)

	2005	2010
Demand	552	635
Supply	558	692
Net Surplus	6	58

Source. Own calculations from International Energy Outlook, 2002, USDOE

Thus, there is a small surplus expected in the world for sweet crude. However, as mentioned in the footnote 'b', this surplus is based on production capacity. If aggregate production figures, which are 97% of the production capacity, are used, the surplus for 2005 turns into a deficit of 10 MMTPA and is reduced to 36 MMTPA for the year 2010.

North America

As shown in table 4.7, North America will be importing about 168 MMTPA of sweet crude in the year 2005. The table below shows the sources for its crude imports for the year 2000.

Table 4.10 Import sources for North America (million tonnes)

Countries/Region	Volume	% share
South & Central America	133.3	29.93
Middle East	129.7	29.12
Total Sour	263	59.05
Western Europe	72.0	16.16
Former Soviet Union	3.2	0.71
Africa	85.6	19.22
Asia-Pacific	14.2	3.18
Total Sweet	175	39.27
Unidentified*	7.3	1.63
Total	445.3	

Source. BP Statistical Review of World Energy, 2001

As shown in the table, Western Europe, FSU, Africa and Asia-Pacific together supplied about 175 MMTPA of crude to North America in the year 2000. The

highest share among these is of Africa, which contributes around 50%, followed by Europe, which contributes around 42%.

As shown in table 4.6, Africa is projected to continue to have a huge surplus of sweet crudes, which means that in the coming decade, Africa will fulfil most of the North American demand for sweet crude.

Europe

Europe, in particular Western Europe, is a large trader of crude oil. In the year 2000, it imported 548.8 million tonnes of crude oil while it exported 96.8 million tonnes. With proven oil reserves of 2500 million tonnes, Europe holds 2% of the total world oil reserves.

The projected demand for imported sweet crude is about 233 MMTPA in the year 2005. Currently, the region imports around 561.5 MMTPA of crude of which 53% is sweet and rest sour. The major import sources for the region are shown below-

Table 4.11 Import sources for Europe (million tonnes)

	Europe	% share
USA[d]	10.1	1.84
Canada	0.6	0.10
Mexico	10.1	1.84
South & Central America	12.5	2.27
Middle East	192.5	35.07
Total Sour	225.8	41.12
Former Soviet Union	164.2	29.91
Africa	132.5	24.14
Asia-Pacific	1.5	0.27
Total Sweet	298.2	54.32
Unidentified*	24.8	4.51
Total	548 8	

Source. BP Statistical Review of World Energy, 2001

Among the sweet crude sources, the important ones are Africa and FSU. This is due to the fact that these regions are nearest to Europe and hence enjoy substantial freight advantage over the other sweet crude producing region in the world - Asia-Pacific.

As elaborated above, Africa will remain the major supplier of sweet crude to this region also and hence Europe is not a potential market for ONGC.

[d] Though crude oil exports from USA are banned, there is a small exception – Alaska North Slope, exports of which were allowed few years back.

Since European crude is also primarily sweet, an analysis of the export destinations of the same will identify the regions where ONGC can also sell its crude, given the freight economies.

The following table shows the export destinations of the European crude.

Table 4.12 Export destinations for European crude (million tonnes)

Country	Volume
USA	43.7
Canada	28.3
Mexico	0.2
S&C America	1.4
Africa	8.4
Australasia	0.1
China	2.6
Japan	0.3
Other Asia-Pacific	7.0
Rest of world	4.8
Unidentified	-
Total	96.8

Source. BP Statistical Review of World Energy, 2001

As is evident, North America accounts for a major portion of the European crudes. Going by the logistics, we can say that Africa and North America will find it economical to import crude from Europe than from India. Asia-Pacific also imported 10 million tonnes of European crude in the year 2000. This probably represents the minimum market ONGC can cater to in the Asia-Pacific region. But whether it will be economical to export the crude oil for ONGC is examined later.

Asia-Pacific

Though Asia-Pacific, with proven reserves of 6000 million tonnes which constitutes 4.2 % of world reserves, exports some quantity of crude oil, it is a net importer. In the year 2000, it produced 380 million tonnes of crude oil but consumed 967 million tonnes.

Taking the reference case of the forecast for both production and consumption of crude oil by the regions as given by IEO, the demand for imported sweet crude for the Asia-Pacific region is estimated at 117 million tonnes. However, given the fact that India is projected to import around 38 million tonnes of sweet crude in the year 2005 (table 5.7), the residual demand in Asia-Pacific is reduced to 79 million tonnes.

FACTS* projects that though the use of sweet crudes in this region will be declining in the view of declining production of the same, the production will decline faster than consumption because of which the region will be importing around 75 million tonnes of sweet crude oil per annum in the year 2005. After adjusting for the fact that some of this demand is originating from India, the sweet crude import demand excluding India comes at around 36.31 million tonnes per annum.

Thus we can say that the total sweet crude demand in Asia-Pacific region, excluding India is expected to be in the range of 36.31 to 78 million tonnes in the year 2005.

Asia-Pacific exports

The table below shows the major export destinations of the region as a whole for the year 2000.

Table 4.13 Export destinations of Asia-Pacific crude (Million tonnes)

Destination	Volume
USA	14.1
Europe	1.5
Canada	0.1
South & Central America	0.3
Western Europe	1.5
Africa	0.2
Total	17.7

Source. BP Statistical Review of World Energy, 2001

However, much of the Asia-Pacific crudes are traded within the region. The intra-region exports amounted to about 122.5 million tonnes or 87.75% of the total crude oil consumed outside the country of origin in the region. Out of the 17.7 million tonnes going outside the region, USA accounts for 14.1 million tonnes and Western Europe accounts for 1.5 million tonnes. This is understandable since Western markets have access to nearer African and North Sea crudes, which are also sweet and have a freight advantage over the Asian crudes in these markets. Carrying the crude from Asia-Pacific to these regions will involve huge freight and hence have to be sold at a discount to remain competitive. They thus do not constitute market for ONGC.

* FACTS Energy Advisory Number 255, June 2001

Asia-Pacific imports

The following table shows the important regions, outside Asia-Pacific, from where Asia-Pacific is importing its crude oil.

Table 4.14 Import sources for Asia-Pacific (million tonnes)

Regions/Countries	Volume	%
USA[e]	6.1	0.9
Mexico	2.4	0.4
South & Central America	4.4	0.7
Middle East	559.8	83.9
Total Sour	572.7	85.9
Western Europe	10	1.5
Former Soviet Union	12.3	1.8
Africa	68.4	10.2
Total Sweet	90.7	13.5
Unidentified*	3.7	0.6
Total	667.1	

Source. BP Statistical Review of World Energy, 2001

As this table shows, Middle East is the dominant supplier of crude to Asia-Pacific region, accounting for about 84 % of total crude imports originating from outside the region. This is understandable given the fact that Asia-Pacific produces primarily sweet crude and hence requires sour crude to obtain an economical product yield.

However, in so far as the crude oil production is lower than the consumption, the region also imported some sweet crude, primarily from Africa, which constituted about 10.2 % of the total Asia-Pacific imports from outside the region.

Intra-region imports, not shown in the table, are also substantial and contribute an additional 126.2 MMTPA.

Given the fact that ONGC crudes are primarily sweet and that India is situated at the far end of the Asia-Pacific region, it can be said that the market left for ONGC is that portion of the total imports which is supplied by Africa and North Sea. In the year 2000, about 68.4 million tonnes of crude oil was imported from Africa and about 10 million tonnes came from Europe which is mainly North Sea. Out of these total Asia-Pacific imports, India accounted for 14.7 million tonnes of African crude and 1.6 million tonnes of North Sea crude in the year 2000[f]. Thus, the Asia-Pacific demand, excluding India, which ONGC could have catered is 62 million tonnes in the year 2000.

[e] Though crude oil exports from USA are banned, there is a small exception – Alaska North Slope, exports of which were allowed few years back.

[f] Source: Oil Coordination Committee

Africa

Nigeria

Nigeria currently holds proven crude reserves of 3100 million tonnes. It reserves have been increasing over the year and now stand at 131% of the reserves at the end of 1990. Nigeria's main export crudes are Bonny Light and Forcados with 37 and 31 API respectively.

Last year, Nigeria produced 103.9 million tonnes of crude and consumed only 13.9 million tonnes, which leaves the exportable quantity of 90 million tonnes. Majority of this surplus is destined for United States (it was fifth largest exporter of crude to United States behind Saudi Arabia, Mexico, Canada and Venezuela in 2000) and Western Europe but Asia is increasingly becoming an important market. Following table shows the major markets for the Nigerian crudes.

Table 4.15 Major markets for Nigerian crudes ('000 tonnes)

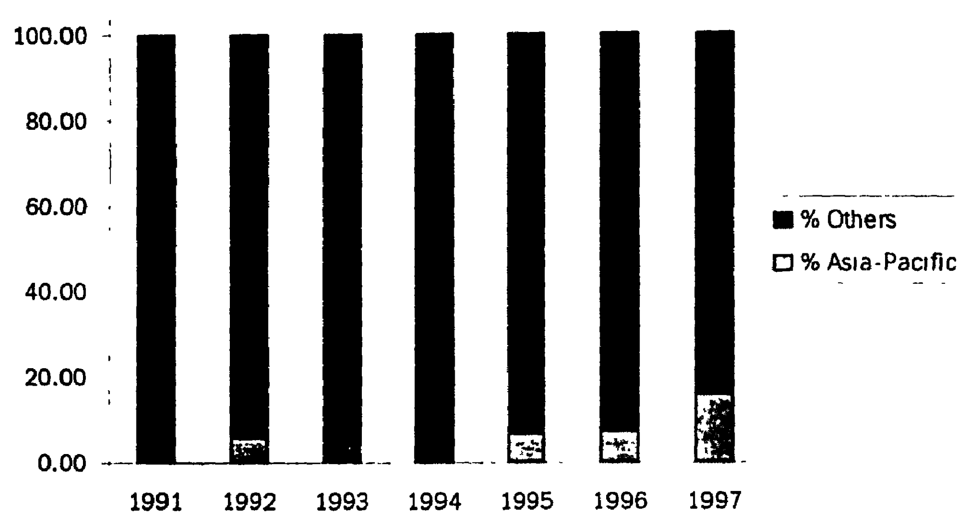
Country	1991	1992	1993	1994	1995	1996	1997
USA	33823	33492	35614	13515	37059	36750	41522
Japan	-	-	-	263	781	1002	1137
Germany	6793	8942	7689	6911	4623	3975	5072
Italy	2780	1663	615	877	590	1224	2007
France	4091	4491	5498	8210	1596	8246	4257
Korea	-	-	-	-	2592	3593	5027
Spain	11149	8574	6068	7050	8599	10417	9656
Netherlands	4244	3653	3905	5067	1874	3023	1900
United Kingdom	1629	1468	193	308	745	1568	214
Singapore	-	-	-	96	257	459	-
Belgium	436	83	269	580	36	-	-
Canada	2590	2586	4094	-	2872	1473	2292
Brazil	1603	130	-	650	379	1189	3729
India	757	4027	-	-	-	-	7518
Sweden	761	626	123	1113	1271	396	391
Greece	-	-	-	122	126	-	-
Thailand	-	-	-	-	70	-	-
Poland	-	-	123	-	-	-	118
Philippines	-	-	-	-	260	132	127
China	-	-	-	-	390	-	-
Finland	368	-	-	-	-	-	-
Portugal	1919	2325	2536	2788	3082	3426	2949
Austria	1712	-	-	-	-	-	-
Australia	-	-	-	-	-	312	291
Total	74655	72060	66727	47550	67202	77185	88207

Source: Energy Yearbook Database, United Nations, various editions

As this table shows, Nigeria has a diversified portfolio of export destinations but most of the countries are located either in Americas or in Western Europe. This is because of the proximity of the country to these markets. Out of total exports

of 88 million tonnes, only 13.9 million tonnes or 15.84% was destined for the Asia-Pacific region in the year 1997. Out of these 13.9 million tonnes, 7.5 million tonnes came to India. Hence, only 6.4 million tonnes was exported to markets other than India. But as the chart below shows, Asia-Pacific is becoming an increasingly important market.

Figure 4.1 Regional shares in Nigerian exports



Source. Energy Yearbook Database, United Nations, Various editions

However, West Africa faces a tough competition in the Western European market from Caspian Sea crudes. As a result of poor demand in the Western Europe and rising output of crudes Caspian crudes like Kazakh Tengiz and Algeria's Saharan Blend, Nigerian crudes are struggling to hold on to the Western Europe market. Sales in May 2002 mainly represent the transfer of crude by refiners like BP, TotalFinaElf and Shell who have substantial production interests in the region[g].

Within the Asia-Pacific region, the main countries, apart from India, are Japan and Korea. Given the proximity of India to Japan and Korea compared to the West Africa, it may be said that, theoretically, ONGC can sell its crude oil in Korean and Japanese markets.

[g] As per the reports of Argus Global Markets, 20 May 2002

Angola

Angola is the fourth largest producer of crude oil in Africa with negligible consumption that leaves it with big exportable surplus. In the year 2000, it produced 36.40 million tonnes of crude oil, majority of which were exported. Recently, Girassol oil field, with estimated reserves of 1 billion barrels, achieved its peak output and will increase the supply to US and Asia-Pacific[h]. Though Girassol falls within processing limits for most refineries in Asia-Pacific, most demand is expected from the US, where it will be valued as a feedstock in complex refineries. Moreover, its floating, storage, production and offloading vessel will be able to store 2 million barrel and allow VLCCs to load which would make long hauls more attractive. The Jasmim field is due on stream in 2003 as a satellite to Girassol and will help maintain its 200,000 b/d plateau. Thus, Angola has the potential to emerge as a major supply source for sweet crude.

Export feasibility for ONGC

While the above analysis shows a huge demand for imported sweet crude in the coming decade in various regions, the possibility of ONGC exporting is examined below.

Policy restriction

In the year 2000-01, India imported around 74 MMT of crude to satisfy its demand for petroleum products. Given this import dependency of 72 %, it is very unlikely that ONGC will be allowed to export its crude oil. The current EXIM policy does not allow free exports of crude oil. Even the private producers under various rounds of NELP are not allowed to export their crude. Thus, it is likely that ONGC will be forced to sell its crude within India only.

Low volume and declining reserves

ONGC produces only about 23 MMT of crude oil per year that translates into 461 thousand barrels per day while the average production in Africa is 711 thousand barrels per day respectively.

Moreover, ONGC's reserves are not projected to grow over the last few years. While Middle East and Africa have added around 21 and 15 thousand million barrels in proven reserves in the decade 1990-2000, India has seen a decline in proven reserves by around 3.3 thousand million barrels over the same time period[i].

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[h] Petroleum Argus Global Markets, Volume XXXII, 4, 28 January 2002.
[i] BP Statistical Review of World Energy, 2001

Export infrastructure

Fields such as North and South Gujarat and Assam are landlocked fields and hence crude from these locations cannot be exported except at a great cost of setting up the required pipelines and other facilities.

The production of KG and Cauvery basin crudes does not constitute a case for exports.

Bombay High is in a slightly better position since it is offshore and has a stabilisation unit at Uran. But ONGC faces a bottleneck in terms of limited DWT of the Jawahar Dweep port. The maximum size of ship it can accommodate is 47000 dwt while the capacity of VLCC ranges from 160,000 dwt to 319,000 dwt. Thus, ONGC can't load a VLCC tanker from Jawahar Dweep port and hence it would be uneconomical for it to export the crude.

One of the important market Asia-Pacific region, Japan, imports huge quantities of crude oil from Middle East and hence cannot be replaced by ONGC. It also imports some quantity from other countries in Asia-Pacific region. They being nearer to Japan have a freight advantage over India. Then Japan mostly imports the crude oil in ULCC tanker, which cannot be loaded in any Indian port.

Quality considerations

The level of BS&W in the ONGC crudes is well above the international norms.

Table 4.16 BS&W in ONGC crudes

Crude	BS&W (% vol)
Bombay High	0.1
North Gujarat	0.3
South Gujarat	0.5
Krishna Godavari Basin	0.3
Cauvery Basin	NIL
Jorhat - Assam	0.1
Moran - Assam	0.2

Source. ONGC

Thus, if ONGC were to export this crude, it would have to discount it heavily in order to remain competitive.

North Gujarat crude has a high degree of naphthenic acid, which corrodes the refinery infrastructure. This would render this crude unacceptable in the international market.

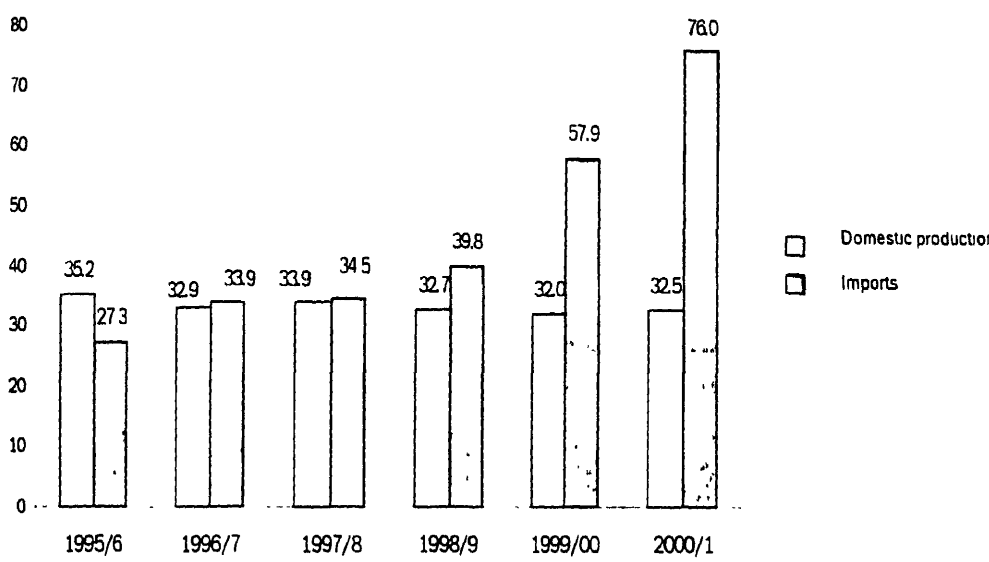
In the international market, all these factors will lead to some discounting of ONGC crudes due to which ONGC will find it economical to sell the crude oil domestically.

5 Oil use by Indian refineries: demand for sweet crude oil

Import dependence

Imports form an important component of our oil consumption, as is evident in the rising import dependency over the years in the figure below.

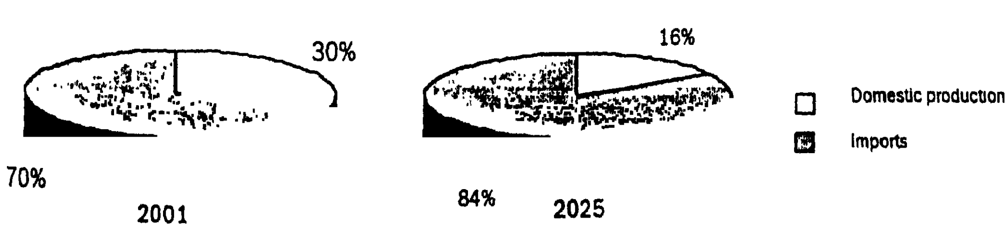
Figure 5.1 Trend in domestic crude oil production and imports (MMT)



Source. CMIE

The Hydrocarbon Vision 2025 (HC Vision) projects India's requirement of petroleum products to be about 370 MMTPA in 2025 and projects domestic crude production in 2025 to be about 60 million tonnes. The balance crude requirement has to be bridged by imports. Thus, crude imports to India in 2025 can be estimated to be about 310 MMT. This implies that share of imports in total oil requirement will rise from about 70% at present to about 84% in 2025.

Figure 5.2 Dependence on crude oil imports

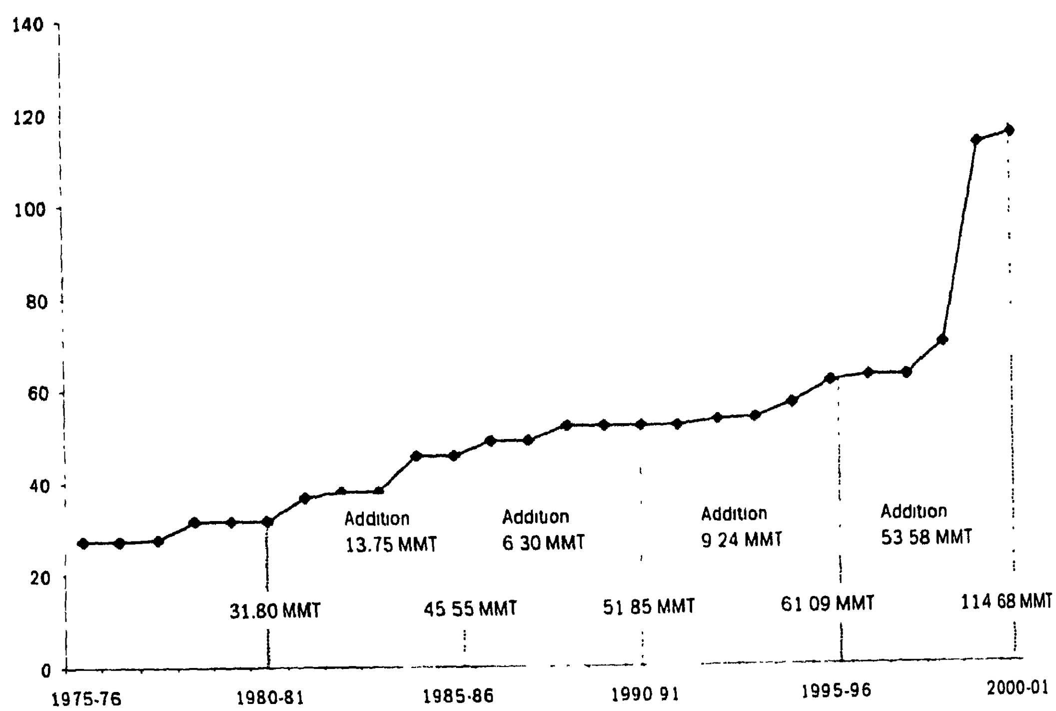


In this section we concentrate on a short-term outlook on crude oil imports - till 2006/7 and largely consider the assumptions made by the Tenth Plan.

Refining capacity in India and projected growth

Figure 5.3 below shows the historical growth of refining capacity in India.

Figure 5.3 Historical growth of refining capacity in India (MMT)



At present there are 17 refineries in India with a total refining capacity of about 114.7 MMT. The refinery-wise installed capacity is presented in Table 5.1 below.

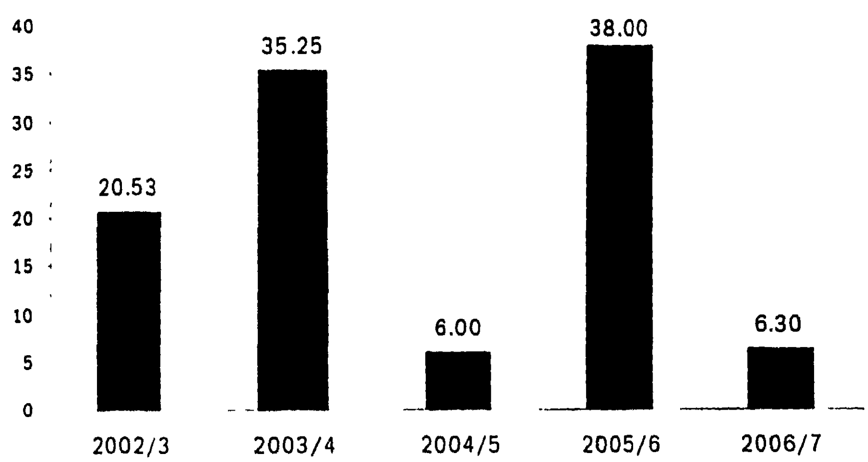
Table 5.1 Refining capacity in India 2001

Company	Location	State	MMTPA
West			
BPCL	Mumbai	Maharashtra	6.9
HPCL	Mumbai	Maharashtra	5.5
North and North-west			
Reliance	Sikka	Gujarat	27
IOC	Koyali	Gujarat	13.7
IOC	Panipat	Haryana	6
IOC	Mathura	Uttar Pradesh	8
East			
IOC	Barauni	Bihar	4.2
IOC	Haldia	W Bengal	4.6
North-east			
IOC	Guwahati	Assam	1
IOC	Digboi	Assam	0.65

Company	Location	State	MMTPA
BR&PL	Bongaigaon	Assam	2.35
IBP/BPCL	Numaligarh	Assam	3
South			
MRL	Madras	Tamil Nadu	6.5
CRL	Cochin	Kerala	7.5
MRL	Nanmanam	Tamil Nadu	0.5
HPCL	Vizag	Andhra Pradesh	7.5
HPCL/Birla	Mangalore	Kamataka	9.69
ONGC	Tatipaka	Andhra Pradesh	0.078
Total			114.668

Considering all the projects under implementation and planned, the Xth Plan projects that the refining capacity in India may be about 220.7 MMT by 2006/07. The year-wise possible capacity additions, as per the Xth Plan, are illustrated in Figure 5.4 below. Refinery-wise details of planned capacity additions under the Xth Plan are presented in table 5.2.

Figure 5.4 Refinery capacity additions (MMT) as planned under Xth Plan



Source. Tenth-Plan subgroup report on refining

Table 5.2 Capacity additions planned/under implementation in Xth Plan period

Year	Refinery	Company	MMTPA
2002-03	Barauni	IOC	1.80
	Haldia	IOC	1.40
	Mumbai	HPCL	0.33
	Narimanam	CPCL	0.50
	Jamnagar	RPL	6.00
	Jamnagar	Essar	10.50
Sub total			**20.53**
2003-04	Koyali	IOC	4.30
	Panipat	IOC	6.00

Year	Refinery	Company	MMTPA
	Mumbai	BPCL	5.10
	Chennai	CPCL	3.00
	Bongaigaon	BRPL	0.35
	Paradip	IOC	9.00
	Jamnagar	Essar	1.50
	Cuddalore	NOCL	6.00
Sub total			35.25
2004-05	Kochi	KRL	6.00
Sub total			6.00
2005-06	Jamnagar	RPL	17.00
	Jamnagar	Essar	12.00
	Bathinda	HPCL	9.00
Sub total			38.00
2006-07	Bongaigaon	BRPL	0.30
	Bina	BORL	6.00
Sub total			6.30
Total X Plan			106.08

However it is uncertain as to which projects will materialise over the time period. As seen from the historical build-up of refining capacity in the country (Figure 5.3), the maximum capacity addition in the last 5 years has been to the extent of 54 MMT. Thus the Xth Plan targets of capacity addition seems overestimated. Also, in view of the emerging surplus situation in some of the petroleum products, a 106 MMT capacity addition in the coming 5 years seems improbable. However, capacity addition in India is somewhat politically influenced and it cannot be ascertained as to which of the projects will materialise and in what time frame.

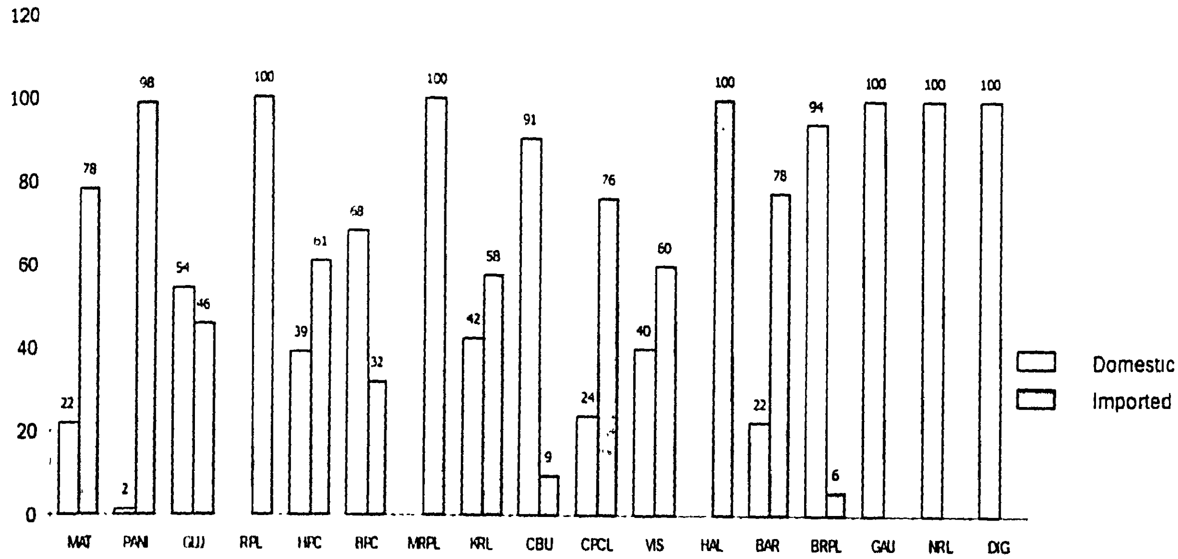
Crude use pattern of existing refineries

The crude throughput by the refineries in 2000-01 had been a little over 103 MMT. In this about 72 MMT was imported and 30 MMT was from indigenous fields. Annexure 5.1 provides crude-wise throughput of refineries for 2000-01.

Domestic crude

The northeastern refineries of Numaligarh, Guwahati and Digboi whereas all other refineries are importing a certain percentage of their crude oil requirement. In 2000/1 only 28% (28.9 MMT) of the crude intake was domestically produced, whereas 72% (74.2 MMT) had to be imported. The percentage of domestic and imported by refineries has been illustrated below.

Figure 5.5 Percentage of domestic and imported crude oil use by different refineries



Source. OCC

Source of crude oil imports to India

Historically most of the crude imports are sourced from the Middle East region. The next largest exporter to India is Africa, especially Nigeria, followed by the Far East country of Malaysia.

Sweet and sour crude intake

Current pattern of crude use by refineries

Among imported crudes, those from Africa are sweet having sulphur content in the range of 0.1 – 0.3% by weight, whereas those from the Middle East Gulf region are sour crudes having sulphur content in the range of 1.5 – 3%.

Table 5.3 provides the major crudes and sources of crude imports to India in 2000-01. Figure 5.6 maps the crude-wise intake by the existing refineries.

Figure 5.6 Crude oil use by existing refineries

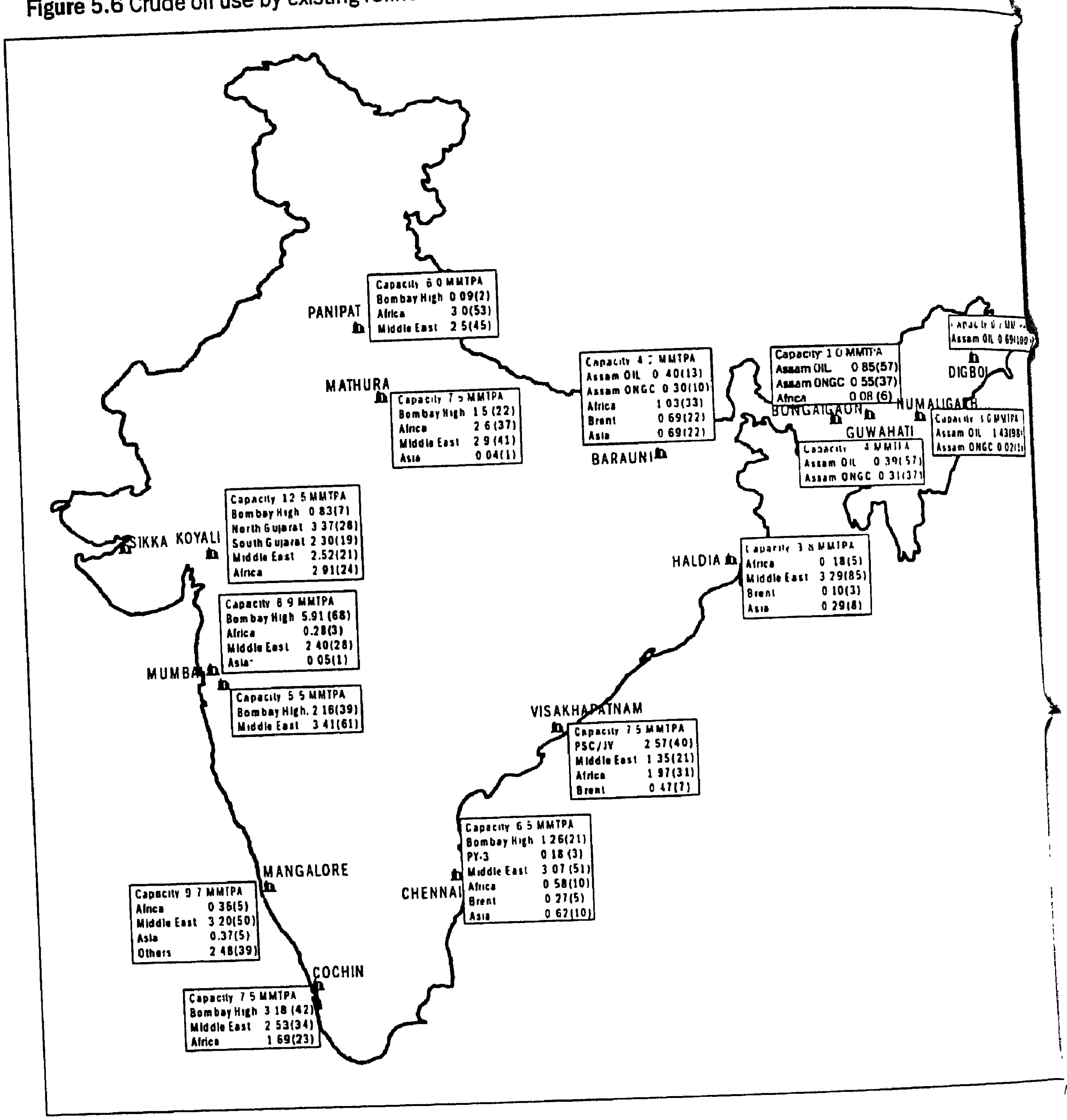


Table 5.3 Major crudes imported by India in 2000-01

Crude	Source	API (°C)	Sulphur (%wt)
High sulphur			
Arab Mix (80.20) and Arab Extra Light	Saudi Arabia	27 85-33 23	2.81-1.90
Basra Light	Iran	32 56	2.18
Iran Mix	Iraq	30 68-32 56	1.50-1.92
Kuwait	Kuwait	30 40	2.59
Dubai	UAE	31.14	1.94
Murban	UAE	39 29	0.80
Umm Shaif	UAE	33.80	1.14
Upper zakum	UAE	37 40	1.51
Lowe zakum	UAE	33.23	1.89
Oman	Oman		
Qatar land	Qatar		
Masila	Yemen	31.05	0.54
Suez Mix	Egypt	32.00	1.50
Zeit Bay	Egypt		
Low sulphur			
Qua Iboe	Nigeria	36.00	0.10
Escravos	Nigeria	36.00	0.10
Forcados	Nigeria	29.70	0.29
Bonny Light	Nigeria	37.00	0.10
Es Sider	Libya	36 70	0.37
Palanca	Angola	37 15	0.18
Soyo Blend	Angola	34.00	0.20
Cabinda	Angola	32 00	0.20
Nemba	Angola	38.78	0.17
Labuan	Malaysia	31.61	0.08
Min Light	Malaysia	32.37	0.08
Tapis	Malaysia	45.27	0.03
Badin	Pakistan		
Brent Blend	Europe		

Source. OCC

Among imported crudes, in 2000-01, the percentage of low sulphur and high sulphur crudes were 26% and 74% respectively. Considering the entire domestic production is of low sulphur, in the total crude usage by refineries, the percentage of low and high sulphur was of the order 47% and 53% respectively. The pattern of high and low sulphur crude use by refineries in 2000-01 is tabulated below.

Table 5.4 Pattern of low and high sulphur crude use by refineries in 2000-01

Region	Refinery	Crude Throughput	Low Sulphur		High Sulphur		Imported crudes	
		(TMT)	(TMT)	%	(TMT)	%	LS %	HS %
West	HPC	5575	2165	39	3410	61	0	100
	BPC	8664	6208	72	2456	28	11	89
	GUJ	12005	9162	76	2843	24	48	52
	RPL	25716	0	0	25716	100	0	100
South	KRL	7520	4771	63	2749	37	37	63
	CPCL	6046	2935	49	3111	51	32	68

Region	Refinery	Crude Throughput	Low Sulphur		High Sulphur		Imported crudes	
		(TMT)	(TMT)	%	(TMT)	%	LS %	HS %
	VIS	6407	4927	77	1480	23	61	39
	MRPL	6438	2550	40	3888	60	40	60
	CBU	579	579	100	0	0	100	0
North	MAT	7134	3968	56	3166	44	43	57
	PANI	5708	2899	51	2809	49	50	50
East	BAR	3122	3122	100	0	0	100	0
	HAL	3875	584	15	3291	85	15	85
North-east	GAU	707	707	100	0	0	0	100
	DIG	679	679	100	0	0	0	100
	BRPL	1490	1490	100	0	0	100	0
	NRL	1451	1451	100	0	0	0	100
India	Total	103116	48197	47	54919	53	26	74

Source. OCC

Future outlook on domestic production and oil imports

Domestic production

As evident from Figure 5.7, domestic crude oil production shows a stagnating trend and the Xth Plan projects that the trend will continue over the plan period with an average production of 32 MMTPA till 2006/7. According to the Xth Plan, domestic crude available for processing by the refineries is estimated to be 31.6 MMT in 2006-07.

Table 5.5 Indigenous crude oil production targets (million tonnes)

	2002-03	2003-04	2004-05	2005-06	2006-07
Assam					
OIL	3.500	3.600	3.750	3.850	4.000
ONGC	2.013	2.057	2.066	2.054	2.004
JVC	0.061	0.061	0.061	0.061	0.061
Gross	5.574	5.718	5.877	5.965	6.065
Net	5.146	5.278	5.426	5.507	5.600
Gujarat					
Gross	6.000	6.075	5.963	5.962	5.828
Net	5.928	6.002	5.891	5.890	5.758
Bombay High					
Gross	14.767	16.014	16.342	16.485	16.271
Net	14.235	15.437	15.754	15.892	15.685
South					
Gross	0.520	0.471	0.393	0.331	0.285
Net	0.518	0.469	0.391	0.330	0.284
Other JVC					
Gross	3.548	3.498	4.368	4.308	4.278
Net	3.509	3.460	4.320	4.261	4.231
Total					
Gross	30.409	31.776	32.943	33.051	32.727
Net	29.336	30.646	31.782	31.880	31.558

Source. Tenth-Plan subgroup report on refining

ide oil imports

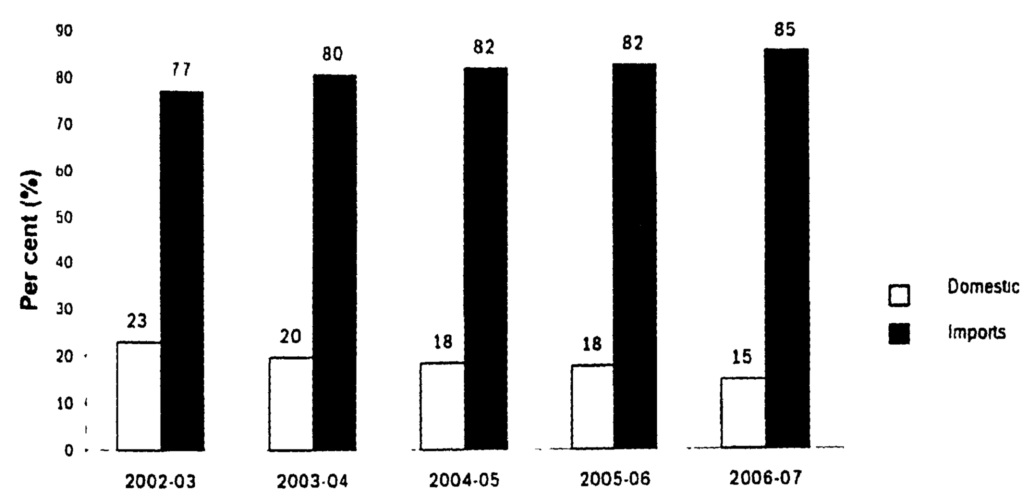
The gap between indigenous crude oil availability (31.6 MMT) and the need for processing in 2006-07 will have to be bridged by imports. In view of the surplus situation emerging in some petro-products, the Xth Plan also provides a base case estimate of crude imports, considering materialisation of 70% of projected refinery capacity additions and 90% utilisation of capacity. The processing requirements and the gross import requirements as projected by the Xth plan – the high and base case scenarios is provided in Table 5.6 below.

Table 5.6 Crude oil processing and imports (MMT) during Xth Plan

	2002-03	2003-04	2004-05	2005-06	2006-07
High Case					
Total processing need	127.672	154.906	174.081	181.392	213.806
Indigenous	29.336	30.646	31.782	31.88	31.558
Imported	98.336	124.26	142.299	149.512	182.248
Gross imports	98.83	124 884	143.014	150.264	183.163
Base Case					
Total processing need	117.572	142.247	146.447	173.047	177.457
Indigenous	29 336	30.646	31.782	31.88	31.558
Imported	88.236	111.601	114.665	141.167	145.899
Gross imports	88.679	112.162	115.241	141.876	146.632

Figure 5.7 below shows the percentage of imported oils in total oil processed (high case scenario). Thus the Xth Plan projections imply increasing share of imported crude oils in total oil needs as refinery capacity is projected to increase substantially and domestic crude production to remain more or less stagnant.

Figure 5.7 Share of imported and domestic crude oils in total processing requirement - high case



Sweet and sour crude intake

The Xth Plan projections

The Xth Plan projects high and base case scenarios of the quantity of high and low sulphur crude oils to be imported in future based on the crude mix as indicated by refineries. This information is tabulated in table 5.7 below. The percentage of low and high sulphur oils in total imports is also listed. Considering all indigenous production to be of low sulphur, the share of low and high sulphur crudes in total processing needs is also indicated in table 5.7 below.

Table 5.7 Share of high and low sulphur oils in total crude requirements (million tonnes)

	2002-03	2003-04	2004-05	2005-06	2006-07
High case					
Total processing need	127.672	154.906	174.081	181.392	213.806
Indigenous	29.336	30.646	31.782	31.88	31.558
Imported	98.336	124.26	142.299	149.512	182.248
High sulphur	70.499	87.375	102.023	107 617	142.774
Low sulphur	27.837	36.885	40.276	41.895	39.474
HS %	55	56	59	59	67
LS %	45	44	41	41	33
Gross imports	98.83	124.884	143.014	150.264	183.163
High sulphur	70.853	87.814	102.536	108.158	143.491
Low sulphur	27.977	37.07	40.478	42.106	39.672
HS %	72	70	72	72	78
LS %	28	30	28	28	22
Base case					
Total processing need	117.572	142.247	146.447	173.047	177.457
Indigenous	29.336	30.646	31.782	31.88	31.558
Imported	88.236	111.601	114.665	141.167	145.899
High sulphur	64.922	80.235	85.828	102.666	118.501
Low sulphur	23.314	31.366	28.837	38 501	27.398
HS %	55	56	59	59	67
LS %	45	44	41	41	33
Gross imports	88.679	112.162	115.241	141.876	146.632
High sulphur	65.248	80.638	86.259	103.182	119.096
Low sulphur	23.431	31.524	28.982	38.694	27.536
HS %	74	72	75	73	81
LS %	26	28	25	27	19

Thus over the years the 70:30 share of high and low sulphur crudes in total imports is expected to be maintained.

Conclusion

In view of increasing dependence on imports, it can be concluded that the Indian market can absorb entire domestic production of ONGC. The Xth Plan projects that over the years low sulphur oil has to be imported, thus it is expected that there will be no dearth of market for low sulphur domestic crude.

Also, the emission-environment norms are getting stricter to reduce pollution. Thus sulphur content in petroleum products like MS and HSD has to be reduced to meet the more stringent norms. According to the Xth Plan one of the ways to reduce sulphur content in MS is to process more of low sulphur crudes. This indicates a rise in demand for low sulphur crudes. The sulphur content norms of various petroleum products as laid down in the Xth Plan is summarised in Annexure 5.2.

6 Crude oil supply infrastructure to Indian refineries

It is important to analyse the existing linkages from various oil fields to the refineries in order to identify the possible infrastructure bottlenecks in marketing in the deregulated era. Oil fields can be linked to refineries via three routes – pipeline, sea (tanker) and/or road. However, domestic crude oil is supplied to refineries mainly via pipelines or shipped from the fields to the refineries except the crude oil from the Chennai refinery and Narimanam GGS, which is moved by road to the Narimanam refinery.

BPCL and HPCL refineries - Mumbai

Domestic crude oil

Oil from the Bombay High, Heera, Neelam, Ratna, Panna and Mukta fields are brought by pipelines to Uran CTF and supplied to the HPCL and BPCL refineries via pipelines. Specifications of the major pipelines are presented in Table 6.1 below.

Table 6.1 Crude oil pipelines from Western offshore fields to refineries in Mumbai

Pipeline	Length (km)	Diameter (Inches)	Owned By	Cost of Transportation (Rs/MT)	Capacity (Design flow)	Thrughput (MMTPA)	Capacity Utilization (%)	Replacement Cost (Rs crores)
BH - Uran	203	30	ONGC	74.94	20 MMTPA	10.631	53.155	557
Heera-Uran	81	24	ONGC	74.94	8 MMTPA	5.074	63.425	179
Uran - Trombay	24	36	ONGC	-	6700 M3/HR	-	-	-
Trombay - BPCL	1.5	24	ONGC	37.00	2000 M3/HR	-	-	1.66
Trombay - HPCL	1	24	ONGC	37.00	2000 M3/HR	-	-	0.8

Source. OCC

It is evident from the capacity utilisation figures that the pipelines from Bombay High fields are grossly under-utilised.

Imported crude oil

Imported crude oils from Middle East and Africa lands at either Vadinar (in the monsoon season) and distributed to the Mumbai refineries or comes to the

Jawahar Dweep port. From Jawahar Dweep, it is carried via pipelines to the Mumbai refineries of HPCL and BPCL. The charter-hire shipping charges from Vadinar to Mumbai have been presented in Annexure 6.1. Four berths are available at Jawahar Dweep port with specifications listed in Table 6.2.

Table 6.2 Crude handling facilities at Mumbai port

Port	Type of berth (No.)	Draft (mtrs.)	Length (mtrs.)	Maximum size of ships (DWT)	% occupancy	
					1998-99	1999-00
Jawahar Dweep	Jetty No 4 Jetty No 1/3	10.97-14.3	244-493	120000 50000	65	53

Source. Basic Port Statistics of India, Ministry of Surface Transport, 1999-00.

Koyali, Mathura and Panipat refineries

Domestic crude oil

Bombay High crude is shipped to Vadinar (at the 2 SBMs near Vadinar) from Jawahar Deep, fed into the Salaya-Mathura Pipeline (SMPL) and supplied to Koyali, Mathura and Panipat refineries. The trans-shipment charges from Mumbai to Vadinar have been presented in Annexure 6.1. North and South Gujarat crudes are supplied from the Navagam and Ankleshwar CTFs respectively to Koyali only. The Vadinar port facilities and crude pipeline infrastructure in the northwestern region is presented in Tables 6.3 and 6.4 respectively.

Table 6.3 Crude handling facilities at Vadinar port

Port	Type of berth (No.)	Maximum size of ships (DWT)	% occupancy	
			1998-99	1999-00
Vadinar	SBM (2)	No restriction	49	54

Source. Basic Port Statistics of India, Ministry of Surface Transport, 1999-00

Table 6.4 Crude oil pipelines to Koyali, Mathura and Panipat refineries

Pipeline	Length (km)	Diameter (Inches)	Owned By	Cost of Transportation (Rs/MT)	Capacity (MMTPA)	Thrughput (MMTPA)	Capacity Utilization (%)	Replacement Cost (Rs crores)
Kalol - Navagam CTF - Koyali	130	14	ONGC	70.66	8	3.36	42	50.25
Ankleshwar - Koyali	94.77	16	ONGC	70.66	3	2.49	83	39.98
SBM1&2 - Vadinar	-	42	IOC	-	-	-	-	
Vadinar - Viramgam	273	28	IOC	76.14	21			
Viramgam - Koyali	141	18	IOC		6 5	6.382	98	
Viramgam - Chaksu	606	24	IOC	84.22	13 5			
Chaksu - Mathura	197	24	IOC		7.5	7.086	94.48	
Chaksu - Panipat	346	24	IOC		6	5.533	92.22	

Source. OCC

Imported crude oil

Imported oils for these refineries land at Vadinar are fed into the SMPL line.

Mangalore refinery

This refinery in the joint sector imports its entire crude requirement.

Table 6.5 Crude handling facilities at Mangalore port

Port	Type of berth (No.)	Draft (mtrs.)	Length (mtrs.)	Maximum size of ships (DWT)	% occupancy	
					1998-99	1999-00
New Mangalore	MRPL Crude jetty (1)	13.00	320	85000	60	60

Source. Basic Port Statistics of India, Ministry of Surface Transport, 1999-00.

Table 6.6 Crude oil pipelines to Mangalore refinery

Pipeline	Length (km)	Owned By	Capacity (MMTPA)
Mangalore jetty - refinery	11	MRPL	5000 (T/hr)

Source. HPCL

Cochin refinery

Other than imported crudes, Koch refinery uses Bombay High which is shipped to the Cochin port. The freight charges have been presented in Annexure 6.1.

Table 6.7 Crude handling facilities at Cochin port

Port	Type of berth (No.)	Draft (mtrs.)	Length (mtrs.)	Maximum size of ships (DWT)	% occupancy	
					1998-99	1999-00
Cochin	Oil terminal (1)	11.70	250	86000	64	97

Source. Basic Port Statistics of India, Ministry of Surface Transport, 1999-00.

CPCL refineries of Manali and Narimanam

Domestic crude oil

Manali refinery uses Bombay High as well as PY-3 (Cauvery) crude. The Narimanam refinery consumes Narimanam, Bombay High, PY-3 and KG onshore crudes. Though it is commonly called the Narimanam refinery, the actual location is Panangudi from where the refinery is connected to the Narimanam oil field via pipeline. Bombay High and PY-3 crudes are brought by road from Chennai. The crude supply routes are detailed in Table 6.8.

Table 6.8 Crude transport routes to CPCL refineries

	Route	Cost of Transportation (Rs/MT)	Capacity (MMTPA)	Thrughput (MMTPA)	Capacity Utilization (%)	Replacement Cost (Rs crores)
Narimanam-Panangudi	Pipeline (ONGC)	7.17	1			1.5
Manali - Narimanam	Road	0.85/MT/KM				

Imported crude oil

Both the refineries are using imported oils. To the Narimanam refinery, imported oils are brought by road from Chennai.

Visakhapatnam refinery

Domestic crude oil

Vizag refinery consumes Ravva offshore crude from the KG Basin. This oil is brought from Ravva fields to Suryasaya Yanam and from there on to the refinery. It also consumes Krishna-Godavari basin crude which is taken to Suryasayanam and mixed with the Ravva crude and taken to the refinery. The total cost to ONGC in moving this crude to the Vizag refinery is Rs 380/MT of which Rs 180/MT is the Ravva processing charge and rest is the cost of transporting this crude to the Suryasayanam.

Imported crude oil

Imported crude lands at Vizag port and transported from thereon to the refinery. The Vizag crude handling capacity has been presented in Table 6.9.

Table 6.9 Crude handling facilities at Vizag port

Port	Type of berth (No.)	Draft (mtrs.)	Length (mtrs.)	Maximum size of ships (DWT)	% occupancy 1998-99	1999-00
Vizag	Liquid Bulk berth-1	10.1	183	36000	76	83
	Liquid Bulk berth-2	9.80	183	36000	82	78

Table 6.10 Crude oil pipelines to Vizag refinery

Pipeline	Length (Km)	Diameter (inches)	Owned by	Cost of Transportation (Rs/MT)	Capacity	Thrughput (MMTPA)	Capacity Utilization (%)
Ravva - S.Yanam	11.5	12	ONGC	-	-	-	-
Vizag Jetty - refinery	9.2	36	HPCL	67.275	5500 (T/hr)	-	-

Eastern and North-eastern refineries

Domestic crude oil

The Digboi, Numaligarh, Guwahati and Bongaigaon refineries consume only indigenous oil from the northeast fields. The crude oil supply network to these refineries is presented in Table 6.11.

Table 6.11 Crude oil pipelines in the northeastern region

Pipeline	Length (km)	Diameter (Inches)	Owned By	Cost of Transportation (Rs/MT)	Capacity (MMTPA)	Thrughput (MMTPA)	Capacity Utilization (%)	Replacement Cost (Rs crores)
Narkhatiya - Digboi	36	8	OIL	5.27	0.5	0.469	93.8	360
Narkhatiya-Moran	51	-	OIL	7.46	1.75	2.447	139.8	10500
Moran-Jorhat	82	-	OIL	12	3.75	3.455	92.1	-
Jorhat CTF-Numaligarh	65	14	-	-	-	-	-	-
Jorhat-Guwahati	268	-	OIL	39.28	4.7	4.293	91.3	-
Guwahati-Bongaigaon	156	-	OIL	22.82	4	3.431	85.8	16000
Bongaigaon-Barauni	600	-	OIL	87.79	3	1.713	57.1	-
Haldia jetty-refinery	2x2.7	32	-	-	-	-	-	-
Haldia - Barauni	524.83	18	IOC	461.5	4.2	2.556	60.9	-

Imported crude oil

78% of the crude thruput by Barauni refinery in 2000/1 had been imported and only 22% had been domestic input. For the Barauni refinery imported crude lands at Haldia. Haldia refinery processed entirely imported crudes. The Haldia crude handling facilities have been depicted in table 6.12 below.

Table 6.12 Crude handling facilities at Haldia port

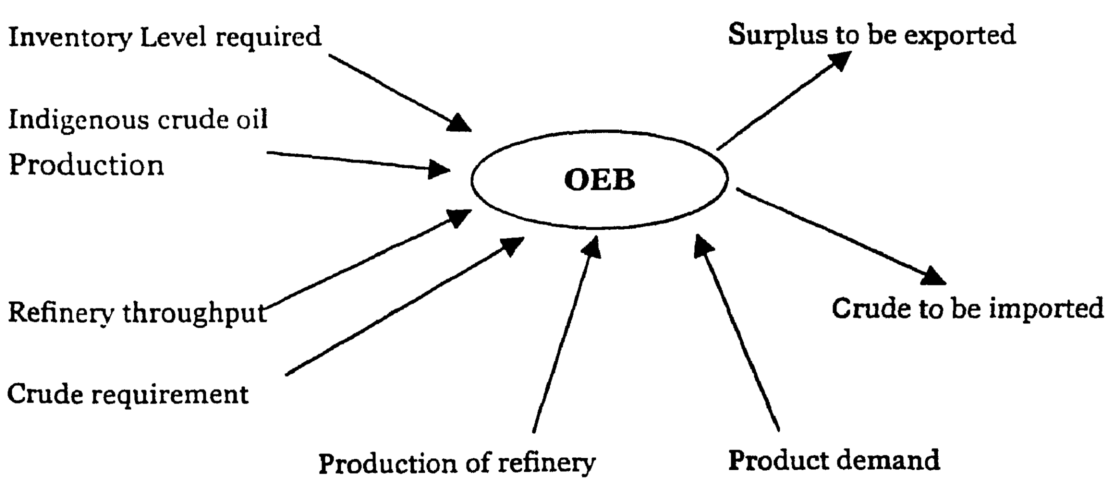
Port	Type of berth (No.)	Draft (mtrs.)	Length (mtrs.)	Maximum size of ships (DWT)	% occupancy	
					1998-99	1999-00
Haldia	Liquid Bulk berth-1	12.20	91.44	90000	67	63
	Liquid Bulk berth-2	12.20	145	150000	60	69

7 Meeting crude oil requirements of refineries: the policy context

Crude oil requirement by refineries

Private and joint sector refineries has been independently importing their crude oil requirement without any government guidance. Recently, even PSU refineries like HPCL and BPCL have been allowed to import their crude oil. Following this, refineries like HPCL and BPC L had set up international trading cell and are preparing themselves for decontrol. HPCL has even concluded crude purchase agreement with Libyan national oil company for the purchase of 3.2 lakh tonne of crude per annum. BPCL is also preparing to source crude independently and is in the process of lying up supply contracts with Saudi Aramco, Yemen Oil and Gas and Kuwait Petroleum.

In the pre-APM era, the allocation of domestic crude oil to refineries was decided by OCC, based on refinery specific requirements (refinery configuration), demand for products and yield of crudes and proximity of refinery and domestic fields. The quantity of imports for PSU refineries were based on the Oil Economy Budget (OEB) prepared by OCC. The Oil Economy Budget generally consists of the following:



Product demand forecasts are made on monthly basis. Demand for products and inventory requirement guide the refinery production plans and these in turn aid

the assessment of crude oil requirement. Quantity required over and above domestic supplies is imported either by term contracts, through term tenders or through spot purchases. Existing policy for crude oil imports is elaborated later in the chapter.

The amount of crude oil required to be imported, type of crude oil necessary, suitable time for procuring crude, time of floating tenders and scheduling of ships are all linked parameters. Factors taken into account while planning crude procurement activities and distribution to various refineries have been listed below. There can be various other factors affecting actual refinery operations.

- crude oil storage capacity
- type of crude to be procured depends on its yield pattern and the petroleum products in demand at that point of time
- amount of the oil to be procured depends not only on demand for its products but also crude already in store
- oil procurement from a particular region depends on availability from that source and loadport conditions
- infrastructure of the refineries – charging tanks, crude distillation units, pipelines from ports to refinery, storage capacity at ports etc
- several issues have to be regarded while deciding the appropriate time of floating tenders
    - administrative delays
    - time taken to arrange for tankers
    - voyage time from the crude source to India leaving enough time for unforeseen slippage. Average voyage times from different sources to India have been tabulated below.

Table 7.1 Average voyage time from various sources to India

Source	Destination	Average voyage time (days)
Middle East	Kandla	5
	Kochi	6
	Haldia	9
Malaysia	East coast India	5
Venezuela	West coast India	45
Africa	East coast India	20
	West coast India	22

- tanker unloading time and possible demurrage delays (average unloading time is 2 days)
- refinery processing time
- time taken for distribution of products.
- proper scheduling of tankers can reduce demurrage costs.

Pre-deregulation policy for crude oil imports for PSUs

The Empowered Standing Committee (ESC) was constituted in the late 1980's to organise crude oil imports through bilateral negotiations with the National Oil Companies or through the tender procedure.

Under the existing system, the quantities and value of import/export of crude oil and petroleum products are assessed on an annual basis. In 1998, the Government permitted the private sector refineries to import their requirement of crude oil directly. Until recently, IOC was the sole canalising agency for import of crude oil and various petroleum products for the PSUs.

The major crude oil markets for India are the Middle East, Africa and Far East regions. The other crude oil markets like Venezuela, Mexico, Vietnam etc., have not been very competitive for import of crude oil mainly due to freight diseconomy. However, lately some of these countries have been offering discounts of about $2-5/bbl on the crude price, which may outweigh the freight economics argument.

The quantity and value of crude oil imports from 1990-91 onwards is presented below.

Table 7.2 Crude imports over the years

Year	Quantity (mill.tonnes)	Value (Rs. Crores)
1990-91	20.699	6118.42
1991-92	23.994	7820.05
1992-93	29.247	10685.86
1993-94	30.822	10688.52
1994-95	27.349	10316.03
1995-96	27.342	11517.00
1996-97	33.906	18538.19
1997-98	34.494	15897.15
1998-99	39.808	14876.46
1999-00	45.01	30650.07

Source. Indian Petroleum and Natural Gas Statistics, various editions

Empowered Standing Committee and the Oil Economy Budget

The ESC was constituted in 1987 and consists of chairman IOC, representatives of Ministry of Petroleum, representatives of Ministry of Finance, representatives of Ministry of Commerce, Director - Finance - IOC, ED-OCC is special invitee of this committee. Recently, the other oil companies namely HPCL and BPCL representatives, have been inducted as observer to this committee.

ESC is responsible for organizing imports of crude oil and petroleum products at best possible prices through bilateral approaches and through the process of tender subject to the condition that the quantity is as per the approval of the

Government. ESC formulates its own guidelines for taking decision and IOC works as a secretariat to this committee.

All imports are finalised directly on a principal to principal basis. Unsolicited offers are not accepted, ESC meets as often as required. As mentioned before crude oil imports are guided by the OEB.

Strategy for import of crude oil

Until now crude oil purchases for the country as a whole have largely relied on term contracts. The gap between crude requirement and the amounts procured on term contracts either from domestic or international sources, has to be filled in by imports on spot basis. Generally as much as possible quantity requirement by refineries is tied up for import on spot basis. The strategy for crude oil imports broadly considers the following:

1. processing need of the refineries
2. security of supplies
3. economic evaluation of the crude oil based on yield pattern advised by OCC
4. diversification of sources
5. bilateral country to country relationships

Term contract

Term contracts are usually annual contracts finalised with the national oil companies of various oil producing countries within the quantity approved by the Government. Such imports are priced at the official selling price announced by these NOCs. Recently, term contracts are being entered into for 3 months period onward, both for crude oil and petroleum products depending upon demand etc.

Term contract for import of petroleum products, i.e. kerosene, diesel is entered into with NOCs having exportable surplus. Such imports are priced at prevailing market price at the time of delivery with a negotiated premium.

Term tender

Import of petroleum products and crude oil are also organised through of term tenders ranging for a period of 3 to 12 months through issuance of term tenders to parties registered in IOC's mailing list.

Imports on a spot basis

Quantity required over and above term supplies and domestic availability is imported on spot basis to cover for variation in production/demand and to

import such grades of crude that are not available through term contracts. These are also organised through registered parties with IOC and by floating a tender of appropriate quantity with other necessary details. These are finalised on prevailing market prices.

The break-up of term and spot crude oil purchases since 1994-95 are give in the following table.

Table 7.3 Share of term and spot purchase

Year	Term* (%)	Spot (%)
1994-95	69	31
1995-96	75	25
1996-97	67	33
1997-98	66	34
1998-99 (P)	58	42

P: Provisional

*Term includes additional cargoes from term suppliers at official selling prices.

The break-up of petroleum product purchases through term contract, term tender and monthly tender is given in the following table.

Table 7.4 Petroleum products purchase (% share)

Year	Term (%)	Term Tender	Monthly tender
1994-95	32	12	56
1995-96	28	9	63
1996-97	33	16	51
1997-98	38	35	27
1998-99 (P)	40	15	45

According to the Estimates Committee Report of 1998/99 purchase decision on term vs. spot contracts is largely governed by the allowable flexibility of operation, the cost of acquisition of crude and bargaining power with the supplier.

To ensure that crude oil imports are made on cost effective basis, the MoPNG has taken the following steps:

1. A large share of requirements of imported crude is procured from the Middle East region which, given its proximity to our country, is cost effective.
2. Finalising the bulk of the imported crude oil requirement through term contracts with NOCs with pricing basis as per the official selling price. Term contracts with various countries ensure diversification of supply sources and provide security of supplies.
3. Uplifting additional cargoes from the term suppliers at their official selling prices, subject to such purchases being economical.

4. Spot purchases are made on a competitive tender basis by inviting offers from registered parties.
5. Continuous efforts are made to expand the basket of crude oils by including new grades found suitable in our refining system in order to increase competitiveness.

Oil imports - pricing mechanism

1. Term and spot import of oil are normally done at market price related formula.
2. For crude, price is generally linked to marker crude oil i.e. Oman, Dubai, Brent etc.
3. For products, price is generally linked to product prices in the main markets such as Arab Gulf, Singapore, Mediterranean etc.
4. Term prices for crude oil are linked to marker crudes and term prices for products are linked to product prices in the Arab Gulf market.
5. Contracts are linked to specific price over a period i.e. monthly average, first 15 days average of the month of loading, first 5 quotes of the month, 5 days after bill of lading or other price out period related to month of loading for crude oil. For products price out period are generally 5 days around bill of lading.
6. Evaluation is based on latest available spot prices published in Platts on the date of evaluation.

IOC floats tenders only to parties registered with it giving specific requirement of crude and time schedules. The parties are required to quote their prices within a fixed time frame. Offers from parties not registered with IOC are not entertained. The offers are evaluated by IOC and placed before the ESC for decision. The crude that provides the best netback is normally purchased and no negotiations are done with any party.

If the quantity available from seller 1 does not suffice, the balance quantity is purchased from seller 2 at the rate quoted by seller 2, and this process is continued till the full requirements are met. However, if the rates are found to be unreasonable, sometimes IOC has floated a tender again for the balance quantity. This system is transparent and IOC is able to get the optimum price under the prevailing circumstances.

Existing crude oil shipping policy

The existing shipping policy for crude oil and petroleum products in India has two most important facets:

(1) All PSUs (with more than 51% government equity) are required to import crude and petroleum products on f.o.b. basis. All exports of petroleum products will be on c&f basis. Exceptions are private companies like Reliance and joint sector companies like MRPL.

(2) All shipping arrangements are centralized through Transchart.

Imports from Nigeria, however, have been on a c&f basis because of the longer haul. It is learnt that in October 2000, Government of India had finalised arrangements with the Government of Nigeria for import of 2 million tonnes of Nigerian crude (from October 2000 to September 2001 in 8 shipments) on fob basis. Some sellers sell crude oil only on c&f basis. In that case, imports could be arranged on c&f basis but only with the approval of the Ministry.

Freight charges

Till March 31, 1998, transportation costs of crude and petroleum products was reimbursed to Shipping Corporation of India (SCI) on a cost-plus basis. SCI was eligible to claim a predetermined percentage of profit over and above the operating costs incurred for carrying crude oil and petroleum products to India. With dismantling of the Administered Price Mechanism this cost plus regime was abolished with effect from April 1, 1998.

IOC was appointed the nodal agency for import of crude oil to India, while SCI was appointed by Ministry of Surface Transport as nodal agency for transportation of crude oil. The freight and charter hire rates as well as other related terms of crude transportation are covered in a Contract of Affreightment (COA) agreed between IOC (on behalf of oil industry) and SCI. These freight rates are market related (based on AFRA).

Advantages and disadvantages of the existing system

1. The existing system ensures that IOC is completely impartial in its supply and trading activity.
2. IOC is arranging supplies at optimal prices but the price may not be the best, as it cannot take advantage of the favourable opportunities in the market.
3. As the procedure followed by IOC is rigid, it often encounters operational problems.
4. It is generally believed that traders and oil companies are able to predict IOC method of tender purchase.
5. IOC does not use risk management tools.
6. IOC does not have flexibility to purchase on C&F basis, which may be commercially attractive sometimes.

So, it is evident that in the existing purchase procedure, the main disadvantage is that it is a tender on premium & thus has an in-built price risk of enormous proportion.

Keeping the above mentioned advantages and disadvantages of existing system in view, the Estimates Committee Report, 1998-99 recommends that the ratio of crude oil purchases through term and spot contracts should be rationalised to ensure (a) availing advantage from any decline in price of crude oil in the international market (b) security of supply.

Policy for crude oil exports from India

The current EXIM Policy stipulates that crude oil exports are canalised and can be exported through the canalising agency, which at present is Indian Oil Corporation.

Also the producers under NELP are allowed to freely market their crude oil production in the domestic market only.

Implications of deregulation of crude oil imports and exports

Deregulation of imports

Government of India aims at complete deregulation of the oil industry by April 2002. Procurement of crude oil (domestic or imported) and selling of products will be entirely driven by market forces. IOC s role as the canalising agency for oil imports will cease to exist. Each PSU refinery will be required to prepare its own strategy for importing crudes.

Recently, the Government of India has permitted all oil companies to source their crude oil requirements independently. Public sector refineries would need to devise their own strategy for

- types of crude oils that need to be refined, in light of the refinery configuration and other techno-economic considerations
- sourcing of the crude oils
- shipping arrangements

The government is initiating steps to allow oil companies to enter into commodity futures to hedge against price risks while importing crude oil and petroleum products.

In light of the above, ONGC may be approached by many domestic refining companies to tie up long term requirements, to the largest extent possible. The attractiveness of the domestic market for ONGC and the negotiating advantages/disadvantages will be discussed further in the subsequent report.

Deregulation of exports

Under the current policy, crude oil exports are canalised through IOC. For the purpose of this study we assume that ONGC will not be able to export its crude oil freely at its own discretion due to rising import dependency of the country.

8 Approach towards marketing strategy

With the dismantling of Administered Price Mechanism (APM), it is expected that ONGC would be free to enter into long term contract for supply of its crude with the domestic refineries at import parity prices. Currently, ONGC is being paid only the international FOB price for similar quality crude traded in the international market. However, the domestic refineries are paying the import parity price to OCC for ONGC crude. The difference between the FOB price and C&F price of crude is mopped up by Oil Co-ordination Committee for balancing the various transactions in the oil pool account. Post deregulation, OCC would not exist and the OPA would be liquidated through issue of bonds to the companies.

In pursuance of the decision of 1997 regarding dismantling of APM, refineries are allowed to source crude for their requirement. To survive in the competitive environment, the refineries are likely to adopt various strategies to reduce their cost of production. One of the major areas where all efforts will be focused would be the procurement cost of crude oil. Innovative strategies would be evolved by the refineries to source crude of their choice at the lowest price. Some of the refineries are under compulsion due to environment regulation, to use only sweet crude up to a certain percentage so that the emission standards are within norms. Thus these refineries would continue to use Bombay High crude provided price of the crude is in line with international marketing trend and developments.

According to the existing export-import (EXIM) policy, ONGC may not be in a position to export crude oil because of the fact that IOC would continue to play the canalisation role and also due to several infrastructural constraints. Even if these constraints are tide over by ONGC, the company is not likely to get price better than the international FOB price. This is a known fact and therefore the refineries may be expect that ONGC would not enter the international market for exporting its crude.

As discussed earlier in Chapter 5, there is an increasing dependency on imported crude by Indian refineries for meeting their requirement. In view of this, the government of India may not easily permit ONGC to export crude to other countries. Furthermore, due to the emerging situation in the Middle East

& neighbouring Afghanistan, oil security for the country assumes considerable importance, national security thus may dominate economic factors for allowing export of ONGC crude.

Therefore though ONGC may be expecting to move towards import parity prices for its crude from April '02, it will not be easy for the company to convince the refineries. Similarly, refineries may not be justified in insisting that they will not pay more than what ONGC is presently getting from the OCC, because ONGC will be committed to pay certain liabilities to the Government of India under various rule from the amount which they get from refineries.

Pricing strategy

The pricing strategy can be thought of as composed of two parts. First is the base price of the crude oil that is dependent on the price of the comparable international crude. Second part is the premium or discount that can be levied/submitted by ONGC to the refinery. These are further discussed below.

Base price

Most international traded crudes are quoted on Free On Board[a] (FOB) basis. Thus, the first option to set the base price is to set it equal to the FOB of the comparable traded international crude. However, in the APM era, the private producers/joint venture producers, were compensated according to the Import Parity Principle, which essentially sets the price of the crude at the cost which the refinery would incur if it were to import crude on its own. Thus, the import parity price involves *inter alia-*

- FOB of the comparable international crude
- Loading port charges
- Sea freight from loading port to unloading port
- LOC charges
- Insurance charges
- Unloading port charges
- Customs duty
- Freight from port to refinery
- Entry tax (if applicable)

[a] "Free On Board" means that the seller delivers the goods when the goods pass the ship's rail at the named port of shipment. This means that the buyer has to bear all the costs and risks of loss or damage to the goods from that point. The FOB term requires the seller to clear the goods for export. **Source.** INCOTERMS 2000

As is evident, the import parity price is substantially higher than the FOB price. ONGC would ideally like to get the import parity price, in line with the practice in the APM era. However, refineries may argue since they are purchasing the crude from the Indian fields, they should not be expected to pay the import parity price which will involves the freight from supply source to India as this will accrue to ONGC for no perceived service. Thus, the base price of the ONGC crudes will be negotiated between ONGC and the refineries on these terms.

However, there is an important difference between imports and indigenous purchase – the central sales tax (since crude oil is a declared good). The sales tax is applicable on the indigenous purchase but not on imports. Thus, to maintain parity between the two, the sales tax has been considered separately and its payment will have to be negotiated. The various options for base price that have been thus examined are:

Option A. ONGC receives fob of comparable international crude and pays central sales tax.

Option B. ONGC receives fob of comparable international crude but does not pay central sales tax.

Option C. ONGC receives import parity price of comparable international crude and does not pay central sales tax.

Option D. ONGC receives import parity price of comparable international crude and pays central sales tax.

Clearly, Option A is the worst option for ONGC while Option C is the best option. However, the final negotiated price may lie somewhere between these options. The avoided cost of importing if the crude is priced at FOB may be shared between the refinery and ONGC in some proportion depending on the negotiating power of each.

Premiums and discounts

Advantages and disadvantages of ONGC vis-à-vis refineries, which will dictate its negotiation power, have been assessed on the following grounds:

1. crude oil quality
2. supply infrastructure to domestic refinery
3. position of field (landlocked or coastal)
4. alternative options for refineries and ONGC
5. security of supplies (taking in imported vis-à-vis domestic crude)
6. exchange rate risks in importing larger amounts of crudes
7. international oil market uncertainties
8. infrastructural constraints in importing more crude oil

Most of these factors have been quantified and culminate into assessing the net discount or premium on the base price for ONGC crude. However certain advantages and disadvantages are qualitative in nature. These can be dealt at best across negotiation table with the potential customer.

Another factor that requires settlement is the custody transfer point as this will determine as to who will bear the cost of transportation of crude to the refinery.

Over and above the central sales tax, ONGC has to pay royalty, cess and corporate taxes to the government. Netting out all the payments and cost of production of ONGC, which according to ONGC officials average around $9/bbl, leaves the surplus for ONGC which will be available to meet its investment commitments in exploration and production. This is based on the assumption that ONGC would ideally like to fund its exploration commitment from its balance sheet and would like to remain zero debt company. This surplus has been calculated field wise and is detailed in subsequent chapters. ONGC will invest Rs 47590 million in various IOR/EOR schemes and expects to increase the reserves by 61.53 million tonnes in 20 years. This works out to $ 2.3/bbl. In comparison, the investments in exploration of other oil companies in Asia-Pacific region for 2000/01 are given in Annexure 8.1, which comes out as $3.5/bbl.

Hence our analysis is essentially a negotiating brief for ONGC, which will also serve as a roadmap for ONGC informing it about its' negotiating partner's as well as its' own strengths and weaknesses. Each of the ONGC fields has been analysed separately and a marketing strategy is framed for each field.

9 Strategy for marketing Bombay High crude

This chapter outlines the various considerations that would determine the potential price of Bombay High (BH) crude.

According to the current policy scenario, ONGC may not be able to export its crude and consequently would have to explore a strategy to get the best prices in the domestic market. As shown in Chapter 6, the tenth plan envisages a growing import dependence and rising demand for sweet crude, implying that the domestic market provides ample opportunity to ONGC to sell its crude. In this context, not only the existing customer base of ONGC, but also potential new customers assumes significance. The current offtake of Bombay High crude by refineries in India is summarized below.

Table 9.1 Refinery wise consumption of BH crude('000 tonnes) 2000/1

Refinery	Total throughput	BH throughput
Existing customers		
HPCL-Mumbai	5575	2165
BPCL-Mumbai	8664	5919
Koyali-Gujarat	12005	832
Kochi	7520	3180
Chennai	6046	1261
CBU-Nanmanam	579	9
Mathura	7134	1555
Panipat	5708	90
Total	**53231**	**15011**
Potential Customers		
Reliance	25716	-
Mangalore	6438	-
Vizag	6407	-

The bulk of BH crude (about 11 MMT) is consumed by the refineries at Mumbai (BPCL and HPCL) and Kochi. Given the proximity of these refineries to the BH field they are expected to procure the BH crude in future as well.

Currently, MRPL uses entirely imported crudes and consumes about 0.4 MMT of African crudes, which have characteristics similar to BH crude. However, given that Mangalore is already importing over 6 MMT of crude, it will not entail any considerable effort or risk to import that 0.4 MMT.

The Bhatinda and Bina refineries are far moved from the BH fields and their date of their commissioning is also uncertain. Hence these refineries have not been considered as potential customers in our analysis.

The Reliance refinery at Jamnagar also imports all its crude requirement at present and ONGC has to negotiate with Reliance on same terms as with other customers. However, the average imported crude procurement cost of Reliance was about \$23/bbl[a] as against an average of \$29.60/bbl for the existing customers of BH crude. ONGC has to keep this in mind while considering Reliance as a potential customer for BH crude. Reliance may not pay high prices for crudes as it is well equipped to process low quality crudes procured at cheap prices.

The Vizag refinery of HPCL is presently using crude from the Ravva fields operated by the Cairns Energy consortium. The price paid for it is fob Arab Light plus 60 cents, which amounts to \$20.3/bbl (for January 2002). Though the joint venture is demanding that its crude is of quality comparable to those of the Far East market and its price should be linked to an average of Tapis and Minas, the case is in arbitration. HPCL being the government nominee, through which Ravva crude has to be sold, it is unlikely that Vizag refinery will replace Ravva with BH crude when Ravva will be a cheaper option. However, BH can replace the imported crude from Africa by Vizag, which amounted to 1.84 MMT in 2001.

The BH crude production profile, as per ONGC estimates, is shown in Table below.

Table 9.2 Projected production of Bombay High crude (million tonnes)

	Current	2002-03	2003-04	2004-05	2005-06	2006-07
Production	15.01#	15.293	15.376	16.085	15.981	15 592

Consumption of BH crude by refineries

Table 9.2 shows a stagnating production trend from BH fields. Thus if ONGC can maintain its existing customers, with whom it has established supply links, it may not have to negotiate with new customers.

Basic price

The pricing options have been discussed in Chapter 8 and are reproduced below.

Option A. ONGC receives fob of comparable international crude and pays central sales tax to the government.

Option B. ONGC receives fob of a comparable international crude but does not pay central sales tax

Option C. ONGC receives import parity price of a comparable international crude and does not pay central sales tax

[a] Annual Report of Reliance Petroleum Limited, 2001

Option D. ONGC receives import parity price of comparable international crude and pays central sales tax.

The detailed calculations for BH crude, evaluating the price base under each option is given in Annexures – 9.1 to 9.9.

Options C and D show the import parity price of BH, benchmarked to an equal mix of Bonny Light and Escarvos, at the custody transfer point Uran.

The difference between the basic price under Option A (the worst option) and the Option C (the best option) is Rs 1591.92/MT ($ 4.72/bbl). This difference represents the margin that ONGC may negotiate for, sharing of which will depend on the negotiating power of the parties involved.

Premium factors for ONGC

Security of supply

Unforeseen emergencies like war or natural calamities have disrupted crude oil production and supply in the past. Greater dependence of refineries on imported crudes may entail risks of supply disruptions. In such situation, refineries will have to operate at a lower capacity. This would increase the fixed cost per tonne, adversely affecting the refinery margins. For existing buyers, replacing BH crude with imported crude will mean an additional exposure to such risks and ONGC can command a premium for that while for potential customers it would mean reduction in such risks.

Annexure 9.10 lists the major disruptions in crude oil supply from major producing countries and the concurrent drop in supply. The average reduction in global supplies during Middle East crisis in 1980 and 1990 had been 3.8 mb/d and had lasted for an average period of 120 days making the overall reduction in supply as 62.21 MMT. The share of India in world oil imports is about 3.5%. If it is assumed that reduction of supply to India will be in the same proportion of the total global supply reduction, about 2.1 MMT of supplies will be unavailable to Indian refineries. Translating the curtailment across the board and assessing its impact on lower crude runs and hence higher fixed costs is taken in this exercise as a possible indicator for security of supplies.

The increase in fixed costs per tonne in case of crude supply disruptions and lower refining capacity utilisation is shown below. The detailed calculations are provided in Annexure 9.11.

Table 9.3 Increase in fixed refining costs

Refinery	Rs/MT	$/bbl
Existing customers		
BPCL	6	0.017
HPCL	3	0.010
Kochi	10	0.031
Chennai	9	0.028
Mathura	4	0.011
Panipat	9	0.028
Koyali	2	0.007
Potential customers		
Mangalore	10	0.029
Vizag	1	0.003

The premium for potential customers has been estimated assuming that they would replace entire imported crude used with the BH crude.

ONGC could command an average premium of $0.029/bbl, since its supplies are relatively assured vis-à-vis the imports by a refinery. However, refineries, which are less dependent on BH crude, may not be inclined to pay a premium for securing supplies from ONGC.

Use of existing infrastructure

As mentioned in Chapter 7 crude from Bombay High is collected at the Uran CTF and supplied to HPCL and BPCL refineries by ONGC owned and operated pipelines. For refineries at Koyali, Mathura and Panipat, BH crude is shipped to Vadinar and fed into the Salaya-Mathura Pipeline. The SBMs at Vadinar and SMPL are owned by IOC. Crude for Kochi, Chennai and Vizag refineries is shipped from Jawahar Deep to the respective ports at these places.

The refineries at Mumbai pay a tariff of Rs 37/MT for transporting the crude from the CTF. These pipelines were laid in 1978, and have an average balance life of eight years, assuming a pipeline age of 30 years. The pipeline tariff for the same in the deregulated scenario is likely to go up to Rs 87.66/MT, as per the recommendations made by ETG. This increase notwithstanding, it may be worthwhile for ONGC to investigate further the case for retaining these assets in comparison to transferring these pipelines to the refineries, keeping in mind the expenses involved in operating and maintaining them, as also issues related to pipeline losses. Such a move may also provide a captive link with these two refineries, and hence result in an assured offtake of 8 MMT from its total production of 15 MMT.

If the pipeline is retained by ONGC, then the cost of transportation is an added factor that has to be negotiated between HPCL/BPCL and ONGC.

For refineries in the North and South, crude is moved by ships and the port handling facilities are not owned by ONGC. This may weaken the case for BH, in the event that these refineries decide to replace BH with imported crude, given that there are no captive infrastructural links forcing the refineries to take BH crude.

Port facilities augmentation for higher imports

In the event that the refineries argue that they can replace all their crude intake from BH by increasing imports, ONGC may not be able to counter it by citing higher costs associated with augmenting port handling facilities. This is because to the extent BH does not land at these ports, the spare capacity could be diverted for higher imports. But a problem one can foresee with this arrangement relates to a likely increase in demurrage on account of unloading of bigger or a higher number of crude parcels arriving at the port.

Greater imports in order to replace the domestic crudes, could imply higher traffic congestion at ports and hence increased demurrage expenses. The oil handling capacity and utilisation of ports at which the concerned refineries import crudes are presented in Table 9.4 below.

Table 9.4 Crude handling capacity at various ports

Port	Type of berth (No.)	Draft (mtrs.)	Length (mtrs.)	Maximum size of ships (DWT)	% occupancy	
					1998-99	*1999-00*
J D Port	Oil Jetty (4)	10.97-14.3	244-493	125000	65	53
Cochin	Oil terminal (1)	11.70	250	86000	64	97
Chennai	Liquid bulk (2)	16 - 17.4	304, 338.94	140000	77, 69	60, 60
Vadinar	SBM (2)			No restriction	49	54
Vizag	Liquid Bulk (1)	10.1	183	36000	76	83
	Liquid Bulk (2)	9.8	183	36000	82	78
Mangalore	Oil jetty (1)	10.5	330	30000	64	67
	MRPL crude jetty	13	320	85000	60	60

Source. Basic Port Statistics of India 1999-2000

The Vadinar port, where imports for Koyali, Mathura and Panipat refineries land has sufficient capacity to cater to greater imports. Hence demurrage from these refineries have been considered as nil. However the % occupancy of Pirpau, Cochin and Chennai ports is high and may entail large demurrage costs in case of greater imports.

Considering cargoes from Nigeria in October 2000 to May 2001, the average demurrage on the West Coast India and East Coast India has been Rs 9.72 /MT

and Rs 9.52 /MT, respectively. The detailed calculations are presented at Annexure 9.12. To this extent ONGC can command a premium on BH crude for avoided demurrage.

Costs of international Procurement

As mentioned earlier there are costs associated with procuring crude internationally, ranging from scanning the market and suppliers, issuing and evaluating tenders, to arranging for ships, foreign exchange, letters of credit. Until now IOC was the sole canalising agency for importing crude on behalf of other Indian refineries[b]. However, in a deregulated scenario companies would prefer to make their own arrangements as evidenced by recent progress made by HPCL and BPCL in signing long term contracts. However, to the extent they can be assured of domestic crude availability as per their quantitative and qualitative requirements, they can limit the costs associated with international purchases.

While no attempt has been made to quantify all the above costs, some tangibles such as costs related to opening a letter of credit, exchange rate risks, and freight diseconomies associated with smaller parcels have been highlighted below. These costs provide the negotiating advantage to ONGC for commanding a premium on the base price.

Letter of credit

The treatment of LC charges while working out import parity formula to price crude and products has varied over time. The Oil Prices Committee, 1976, recommended a flat LC charge of Rs 1/MT while the Oil Cost Review Committee, 1984, adopted a stand that the LC charges should be compensated separately and hence was not included in its recommended price build-up. Currently, the Oil Coordination Committee uses the norm of 0.3% on cost & freight for determining the LC charges payable by the refinery.

The level of LC charges depends on the creditworthiness of the buyer. IOC, being a fortune 500 company, may be paying a lower LC charge while any standalone refinery, importing crude independently for the first time, may be required to pay a higher LC charge.

The table below shows the increase in the cost of crude imports on account of 0.1 percentage point increase in LC charges.

[b] This however excludes the private and JV refineries.

Table 9.5 LC Charges

Refinery	Rs/MT	$/bbl
Existing customers		
BPCL/HPCL	7.35	0.021
Kochi	7.32	0.021
Chennai	7.35	0.021
Mathura	-	-
Panipat	-	-
Koyali	-	-
Potential Customers		
Vizag	7.39	0.021
Mangalore	7.33	0.021

To the above extent, ONGC could ask for a premium for relative ease in procuring domestic crude supplies.

Foreign exchange risk

Refineries need to factor in foreign exchange risks for crude oil imports. Refineries can be exposed to two types of risks which are discussed below.
a) The FOB value (in USD) of the crude oil is converted into rupee terms at the actual telegraphic transfer rate of exchange as obtained on the date of remittance[c].

Since the imports are in dollar denominations, there is a substantial exchange rate risk involved in the process as the rupee can depreciate[d] very quickly which would increase the crude cost. However, for domestic crude such risks do not apply, since payment would be made in the domestic currency.

For instance a 1% depreciation of the rupee will increase the cost of importing from the base case[e], as shown below.

Table 9.6 Exchange rate risks

Refinery	Rs/MT	$/bbl
Existing Customers		
BPCL/HPCL	81.66	0.242
Kochi	81.30	0.241
Chennai	81.74	0.242
Mathura	82.14	0.243
Panipat	81.74	0.242
Koyali	81.74	0.242
Potential Customers		
Vizag	82.03	0.243
Mangalore	81.48	0.241

[c] Oil Prices Committee, 1976, Chapter XIII, Page 100

[d] During 1999-00, the rupee depreciated by about 2.9% from the annual average of Rs. 42.07 per US dollar in 1998-99 to Rs. 43.33 in 1999-00 (Economic Survey, 2000-01). The depreciation was steeper in 2000, by end of January 2001, the rupee had depreciated by 6.1% from March 2000. This can have considerable bearing on cost of importing crudes.

[e] The base case foreign exchange rate taken for the purpose of this study is Rs 46 = $1.

ONGC could use the above argument to build a premium on its base price.
b) Another type of risk that the refineries could be exposed to is the impact of changes in exchange rate between the time it buys foreign currency to pay for its crude oil purchases to the time the actual delivery takes place (assuming no hedging has been resorted to cover the exchange rate fluctuation risk).

Freight diseconomies

Presently, the imported crude oil requirements of the coastal refineries like HPCL and BPCL is handled by IOC, which brings crude at Vadinar in large tankers from where it is distributed domestically. However with deregulation, refineries importing independently may have to import in smaller vessels that will increase freight expenses, unless they continue with the present arrangements with IOC, or if BPCL, HPCL try to synchronise their international purchases and use common shipping arrangements. Port capacity constraints may also force the refineries to import crude in smaller tankers (see table 9.3). Thus replacement of domestic crude with imports may prove costlier.
The worldscale (WS) rates for crude oil imports from Nigeria during the year 2001 are tabulated below.

Table 9.7 Freight rates for crude imports from Nigeria in 2001 (as per Worldscale 100)

	Rates to Indian ports ($/MT)					
Loadport	Vadinar	Mumbai	Cochin	Chennai	Vizag	Mangalore
Bonny Offshore Terminal	13.20	13.06	12.45	13.21	13.68	12.75

AFRA assessments for February 2001 for LR II and VLCC are 150WS and 116.9 WS respectively. This reveals that the freight rates for LR II will be about 30% higher than for VLCC at the same WS, which clearly shows the advantage in bringing in larger vessels. The increase in cost of crude imports on account of importing in LR-II as compared to VLCC for select refineries, is as follows:

Table 9.8 Freight diseconomies

Refinery	Rs/MT	$/bbl
Existing Customers		
BPCL/HPCL	220.53	0.654
Kochi	210.49	0.624
Chennai	223.32	0.662
Mathura	-	-
Panipat	-	-
Koyali	-	-
Potential Customers		
Vizag	231.01	0.685
Mangalore	215.56	0.639

The combined requirement of imported crudes by the three IOC refineries in the north-western region is 16.69 MMTPA while the maximum capacity of a VLCC tanker is 0.319 MMT. Thus, IOC can sustain a vessel size of VLCC for its imported crude requirement and hence cannot be expected to pay a premium on the account of bringing crude on a smaller vessel.
An addition of this extent to the cost of imported crude could be used by ONGC to argue for a premium on supplying its crude.

Discount factors for ONGC

In the deregulated scenario, the refineries paying the price on international parity will demand an international quality crude. However, the BS&W of BH crude, at 0.1%, is higher than the international standard of 0.02%[f], above which the crude is discounted. Thus, BH crude is also likely to be discounted on this account. Thus, either ONGC has to treat the crude to bring it to the international standard or negotiate a discount for quality, with the refineries.

As provided by ONGC, it costs about Rs. 100 million to desalt 1 MMT of crude. Desalting BH crude (15 MMT) would cost around Rs. 1500 million according to estimates provided by ONGC. The annutised capital cost is estimated at 16.47 Rs/MT. It would add to the cost of production and impact the margin ONGC could make on crude sales. The detailed calculations are given in Annexure 9.13. Alternatively, the cost may be taken as the discount ONGC may
- eries for the high BS&W content.

[f] This is an international standard normally included in the crude purchase contracts. However, the acceptability of a crude to the buyer, irrespective of the BS&W content, is solely dependent on the buyer and can be negotiated between seller and buyer.

Summary table

Table 9.9 Summary of premiums and discount

		Existing Customers							Potential Custom	
	Unit	BPCL	HPCL	Chennai	Kochi	Mathura	Panipat	Koyali	Vizag	Mang
Premium factors for ONGC										
Security of supplies	Rs/MT	6	3	9	10	4	9	2	1	[illegible]
Demurrage charges	Rs/MT	9.72	9.72	9.52	9.72	0	0	0	9.52	[illegible]
LC Charges	Rs/MT	7.35	7.35	7.35	7.32	0	0	0	7.39	[illegible]
Exchange rate risks	Rs/MT	81.66	81.66	81.74	81.3	82.14	81.74	81.74	82.03	[illegible]
Freight diseconomies	Rs/MT	220.53	220.53	223.32	209.21	0	0	0	231.01	[illegible]
Total Premium	**Rs/MT**	**325.26**	**322.26**	**330.93**	**317.55**	**86.14**	**90.74**	**83.74**	**330.95**	[illegible]
Discount factors for ONGC										
BS&W problem	Rs/MT	16.47	16.47	16.47	16.47	16.47	16.47	16.47	16.47	[illegible]
Total Discount	Rs/MT	16.47	16.47	16.47	16.47	16.47	16.47	16.47	16.47	[illegible]
Average Net Premium	Rs/MT	308.79	305.79	314.46	301.08	69.67	74.27	67.27	314.48	[illegible]
Average Net Premium	$/bbl	0.916	0.907	0.933	0.893	0.207	0.220	0.200	0.933	[illegible]

Strategic option

As the above analysis shows, BH crude is in a position to command a premium over and above the basic price from all the refineries. Applying this premium to all the four options for basic price for BH crude yields the following surplus for ONGC. The detailed calculations are from Annexure 9.1 to 9.9.

Table 9.10 Surplus for ONGC ($/bbl)

Refinery	Option A	Option B	Option C	Option D
BPCL - Mumbai	1.86	2.37	5.44	4.81
HPCL - Mumbai	1.86	2.37	5.44	4.82
Koyali	1.40	1.91	4 98	4.34
Mathura	1.40	1.91	4.98	4.35
Panipat	1.41	1.92	4.99	4.36
Kochi	1.85	2 36	5 43	4 80
Vizag	1.88	2.38	5.45	4 82
MRPL	1.86	2.37	5 44	4.81
Chennai	1.88	2.38	5 45	4 82

Given the ONGC's exploration commitment of $2.3/bbl, it seems that ONGC should negotiate for Option C. However it should accept no less than Option D which means that it should get the import parity price for BH and may pay the sales tax on behalf of the refineries.

10 Strategy for marketing North and South Gujarat crudes

This chapter outlines the various considerations that would govern the potential price of Gujarat crudes.

Koyali is the only refinery that processes North and South Gujarat crudes. To the extent that ONGC has no alternate infrastructure to supply these crudes to any other refinery, either in India or abroad, ONGC is likely to continue to be dependent on Koyali refinery for Gujarat crudes.

Koyali takes about 5.5 million tonnes of imported crudes via the Salaya-Mathura pipeline, owned and operated by IOC. However, the capacity of this pipeline is almost completely utilised, and hence Koyali is also a captive buyer for ONGC, at least till the time the capacity of the pipeline is enhanced for the entire throughput of the refinery.

Reliance's Jamnagar refinery is the only other operating refinery in the region and hence can theoretically take the Gujarat crudes. However, the average procurement cost for Reliance for the year 2000/01 was $23.18/bbl (Annual Report of Reliance Petroleum Limited, 2001) which is lower than Koyali refinery's $29.64/bbl. This is because of the Reliance refinery's ability to process the low quality crudes available at cheap prices. This point has to be kept in mind while negotiating with the refineries.

Gujarat fields have been projected to have a stagnant production for the 10th five-year plan period, as shown in the table below.

Table 10.1 Projected production from Gujarat fields (MMT)

	2002-03	2003-04	2004-05	2005-06	2006-07
Mehsana	2.337	2.522	2.637	2.886	2.979
Ahmedabad	1.473	1.504	1.477	1.438	1.392
Total North Gujarat	3.81	4.026	4.114	4.324	4.371
Ankleshwer	2.09	1.949	1.749	1.538	1.357
Cambay	0.1	0.1	0.1	0.1	0.1
Total South Gujarat	2.19	2.049	1.849	1.638	1.457
Total	6.00	6.075	5.963	5.962	5.828

Source. ONGC

Thus, if ONGC can maintain the existing supply relationship with the Koyali refinery, it may not need to look for alternate buyers.

The specific linkages of the ONGC fields to the Koyali refinery will play an important role in the overall marketing strategy. A few salient features are-

1. The supply pipelines were installed nearly thirty years back and may need replacement in a few years.
2. The supply infrastructure is completely owned and maintained by ONGC.
3. The ONGC fields are the nearest source of crude for the Koyali refinery.
4. The Vadinar-Koyali section of the Salaya-Mathura pipeline is almost completely utilised.
5. The only other existing refinery in the region, Reliance, does not have the infrastructure to move ONGC's crude to its location.

Basic price

As elaborated in chapter 10, there are four options ONGC faces while negotiating the basic price of the crude. These are reproduced here.

- **Option A** – Price the crude at FOB of the benchmarked crude at custody transfer point but pays the sales tax on the crude.
- **Option B** – Price the crude at FOB of the benchmarked crude at custody transfer point.
- **Option C** – Price the crude at the Import Parity Price (IPP) of the benchmarked crude at the custody transfer point.
- **Option D** – Price the crude at the IPP of the benchmarked crude at the custody transfer point but pays the sales tax on crude.

Option A is the worst option while Option C is the best case. The detail calculations of these options are at Annexure 10.1.

As the tables in Annexure 10.1 show, the difference between Option A and Option C is Rs 1601.56/MT or 4.749 \$/bbl which then represents the negotiating margin.

Among many other things that have to be negotiated between Koyali and ONGC is cost of transporting the crude from Vadinar to respective Central Tank Farms (CTF) in North and South Gujarat. Ideally, if the pricing is done on import parity basis, these costs should be borne by the refinery if the custody transfer point are the CTFs.

However, the import parity have been calculated at Vadinar and not at respective CTFs because the imported crudes for the refinery land at Vadinar and the refinery may not pay anything more than the landed cost of imported crude at Vadinar since it has it own pipeline from Vadinar to Koyali.

The methodology detailed in Chapter 10 is followed here. First the possible reasons for premiums or discount are discussed and then the final price

recommended keeping in mind the $ 2.3/bbl exploration commitment by ONGC.

Premium factors for ONGC

Security of supplies

As elaborated in Chapter 10, there is always a risk of disruption in supplies attached with crude imports since the major crude export originate from politically sensitive areas. Thus, increasing the import dependency will entail extra risks of supplies for a refinery. The risk of disruption is relatively lower for the domestic crudes.

The increase in fixed cost per tonne on account of lower capacity utilisation due to disruption in supplies for Koyali refinery for North and South Gujarat crudes is shown below. The detailed calculations are at Annexure 10.2.

Table 10.2 Increase in fixed cost

Refinery	Rs/MT	$/bbl
North Gujarat	3.868	0.011
South Gujarat	3.441	0.010

Thus, ONGC is in a position to command a premium for its supplies being more secured than imported crudes. However, Reliance is currently importing its entire crude requirement and a quantity of 5.5 MMT is too small to change the risk profile of 25.716 MMT of crude portfolio.

Existing infrastructure

One crucial factor in negotiations will be existing infrastructure at the disposal of both refinery and ONGC. ONGC owns the supply pipelines moving crude from its CTFs in North and South Gujarat to the Koyali refinery. Koyali imports around 5.5 MMT of crude via Salaya-Mathura pipeline (SMPL).
If the capacity of SMPL is enhanced or a new pipeline is laid with enhanced capacity, this would mean that Koyali would have an edge over ONGC in negotiations. On the other hand, if the status quo is maintained, Koyali will be at relative disadvantage since it will be dependent on Gujarat crudes to run its refinery at maximum utilisation.

The domestic crude supply pipelines are nearing their economic life and may have to be replaced shortly. In such a scenario, the question arises as to who should replace the pipelines.

In view of the fact that Koyali refinery expansion has been put on hold (The Economic Times, 12th February, 2002) and thus the possibility of capacity expansion of SMPL (or at least the Viramgam-Koyali) section of the pipeline is remote, these pipelines can be transferred to the refinery as this would avoid all the claims and cost for ONGC regarding quantity differences, pilferage and theft and eventually replacement.

Augmentation of facilities for higher imports

Imported crude for the IOC refineries in the northwestern region are received at an offshore SBM off the coast of Vadinar. This SBM has no capacity constraints and the occupancy has also not been high (Table 9.4). This means that importing an additional quantity of 5.5 MMT is unlikely to cause any additional expenses for IOC.

However, the capacity of the SMPL pipeline is completely utilised and cannot support extra imports of 5.5 MMTPA. This means that to replace Gujarat crudes by imported crudes, IOC will have to augment the capacity of SMPL. By thumbrule estimates, it costs around Rs 0.1 million per inch diameter per kilometre to install a crude pipeline. Taking this estimate, it will cost around Rs 745.2 million to set up a new pipeline of 18" from Vadinar to Koyali which would yield an annutised capital cost of Rs 17.17/MT. Thus, ONGC can command a premium to this extent on the account of avoided cost of augmenting the facilities for extra imports. The detailed calculations are at Annexure 10.3.

Again, Reliance imports its entire throughput of crude and hence does not need to augment any import infrastructure. Thus, it will not pay any premium on this account.

Costs of international procurement

As detailed in Chapter 10, there are certain costs which have to be incurred during the procurement of international crude. Thus, the refineries taking domestic crude will be avoiding all these additional costs of imports. While it is not possible to quantify all the costs involved in the procurement process, three important and most tangible have been highlighted.

Letter of credit

As mentioned in Chapter 10, the letter of credit charges for importing crude vary from buyer to buyer. IOC being a Fortune 500 company and because of the fact that it has been importing crude for many years would not be required to pay an extra LC charge. Thus, this factor will not enable ONGC to command a

premium. By the same logic, Reliance, by the virtue of being an internationally recognised company, is not expected to pay a higher LC charge.

Foreign exchange risk

As elaborated in Chapter 10, since imports are on dollar basis, there is a considerable foreign exchange risk involved, assuming that refineries are not hedging for this risk. The risk is essentially the increase in the fob price of crude, expressed in rupee terms, due to depreciation of rupee, which makes the final price higher than expected. For instance, a 1% depreciation in rupee will raise the import cost of an equivalent quality crude for Koyali refinery by Rs 81.87/MT ($0.242/bbl). Thus, ONGC can build up a premium on its base price on this account.

Freight Diseconomies

The combined requirement of imported crudes by the three IOC refineries in the northwestern region is 16.69 MMTPA. The maximum capacity of a VLCC tanker is 319,000 MT. Thus, IOC can sustain a vessel size of VLCC for its imported crude requirement and hence cannot be expected to pay a premium on the account of bringing crude on a smaller vessel.

However, there are certain factors that will force ONGC to yield a discount on the following account.

Discount factors for ONGC

Quality of ONGC crudes

The BS&W content in the North and South Gujarat crudes is 0.3% and 0.5% respectively. This is higher than the internationally accepted range of 0.02-0.2% of BS&W. If ONGC aims to get internationally competitive price in a deregulated scenario, it will have to meet the international quality also. Thus, it would have to reduce the BS&W content in its crudes. A desalter plant at Kalol is already desalting the North Gujarat but additional costs may have to be incurred for the same for South Gujarat crude. According to estimates given by ONGC, it costs around Rs 100 million to desalt 1 MMT of crude which gives an annutised capital cost of Rs 22.3/MT for desalting the 2.3 million tonnes of South Gujarat crude. The detailed calculations are at Annexure 10.4.

No alternative for ONGC

Even if ONGC were allowed to export the crude, the lack of supporting infrastructure would have prevented ONGC from doing so. The only other refinery that can possibly move ONGC crudes is the Reliance's Jamnagar refinery. But there is no infrastructure to move the crude from ONGC's CTFs in North and South Gujarat to the Reliance's refinery.

Reliance refinery has the ability to process the cheapest crude. So it would not pay to ONGC anything above its average procurement cost. Thus, cost of transporting the crude from North and South Gujarat to Jamnagar will reduce the realisation to ONGC.

As per the ETG recommendations, the tariff for new crude pipeline comes out to be Rs 1.23/MT/Km[a]. The average distance from Nawagam and Ankleshwar to Jamnagar is 311 and 484 kms respectively. Thus the cost of transportation is estimated as Rs 382.53/MT and Rs 595.32/MT respectively. These can be taken as the discount that ONGC may have to yield to Koyali.

Summary table

Table 10.3 Summary of premiums and discounts for Gujarat crudes

	Rs/MT	$/bbl
Premium factors for ONGC		
Security of supplies		
a) North Gujarat crude	3 868	0 011
b) South Gujarat crude	3 441	0 010
Augmentation of facilities for imports	17 17	0 051
Cost of international procurement		
Exchange rate risks	81 87	0 243
Total		
a) North Gujarat crude	102 908	0 305
b) South Gujarat crude	102 481	0 304
Discount factors for ONGC		
Inferior quality crude		
a) North Gujarat crude*	-	
b) South Gujarat crude	22 3	0 066
No alternative for ONGC		
a) North Gujarat crude	382 53	1 134
b) South Gujarat crude	595 32	1 766
Total		
a) North Gujarat crude	382 53	1 134
b) South Gujarat crude	617 62	1 832
Net discount		
a) North Gujarat crude	279 622	0 829
b) South Gujarat crude	515 139	1.528
Average Discount	375 165	1 112

* This does not takes into account that fact that North Gujarat crude is highly acidic and hence ONGC will have to give a discount on this account also which may be negotiated with the refinery

[a] The ETG gives the pipeline tariff as Rs 1 13/MT/KM Escalating it by 80% of the WPI index for each year after 1999-00, we have the tariff as Rs 1.23/MT/KM.

Strategic option

As the above analysis show, ONGC will probably have to give a discount to Koyali refinery for its North and South Gujarat crudes. Applying this discount to all the four options and deducting the various charges ONGC will have to pay, the following surpluses emerge.

Table 10.4 Surplus for ONGC from Gujarat fields ($/bbl)

Refinery	Option A	Option B	Option C	Option D
Koyali	0.57	1.08	4.17	3.53

As this table shows, Option A and Option B are not sustainable for ONGC. Under Option D, given the exploration commitment of 2.3 $/bbl, the net left is $1.23/bbl which gives 34.8% return to ONGC which is very fair. Thus, ONGC should not accept anything less than Option D.

11 Strategy for marketing Cauvery basin crude

This chapter outlines the various considerations that are important in determining the price of Cauvery basin crude.

With production volume of 0.431 MMT, many refineries do not process the Cauvery basin crude. The CBU refinery of Chennai Petroleum Corporation (CPCL) takes the entire Cauvery basin crude. Other refineries in this region are CPCL Chennai, KRL Kochi and HPCL Vizag. However, since CPCL owns both Chennai and CBU refineries, it can be assumed that Chennai refinery would not compete with CBU refinery for this crude. Moreover, given the policy restriction along with small production quantity, it can be assumed that this crude will not be exported.

The production from the Cauvery Basin is projected to decline in the coming years as shown below.

Table 11.1 Projected production from Cauvery field (MMT)

	2002-03	2003-04	2004-05	2005-06	2006-07
Cauvery	0.307	0.295	0.243	0.201	0.17

Source. ONGC

This means that the possibility of this crude being processed by any other refinery is remote since no one would like to enter into a purchase contract for a declining field.

There are two other refineries in the region – Kochi and Vizag. But it will be difficult to term these as prospective buyers due to two main reasons. Firstly, Vizag refinery does not process Arab Light crude to which the Cauvery crude has been benchmarked. Since no assumption can be made regarding the refinery configuration, it cannot be assumed that the refinery will be able to process the Cauvery crude.

Secondly, the cost of transporting the Cauvery basin crude to the Vizag and Kochi refinery will be prohibitive. The crude would first have to be moved to Chennai from where it will have to be transported via sea route to Kochi refinery and perhaps via road to Suryasayanam from where it will be pumped to Vizag through the existing JV pipeline. Infact, the cost of transporting even the KG crude to the Vizag refinery were prohibitive enough for ONGC to commission its

own small refinery at Rajahmundry to process the KG crude. Thus, it can be assumed that Cauvery basin crude cannot be moved to any refinery except CBU.

On the other hand, CBU refinery is also handicapped by the lack of access to any other source of crude. It does take in 0.054 MMTPA of imported crude but that represent only 9.32% of the total refinery throughput. These imported crudes are transported via road from Chennai, which makes the cost of transportation as high as Rs 284/MT. Due to this high cost of transportation, CBU is mainly dependent on Cauvery basin crude which currently represents 75% of its throughput.

It can be thus concluded that with respect to Cauvery basin crude, ONGC and CBU are in a mutually beneficial relationship, breaking of which will be costly for both. None of them have any other viable option to sell or procure crude.

Basic price

As elaborated in chapter 8, there are four options ONGC faces while negotiating the basic price of the crude. These are reproduced here. The benchmarked crude, as elaborated in Chapter 4 is Arab Light. The detailed calculations are at Annexure 11.1.

- **Option A** – Price the crude at FOB of the benchmarked crude at custody transfer point but pays the sales tax on the crude.
- **Option B** – Price the crude at FOB of the benchmarked crude at custody transfer point.
- **Option C** – Price the crude at the Import Parity Price (IPP) of the benchmarked crude at the custody transfer point.
- **Option D** – Price the crude at the IPP of the benchmarked crude at the custody transfer point but pays the sales tax on crude.

The calculations for import parity prices have been done for Chennai port and exclude any transportation charges from Chennai to CBU due to two reasons.

First, these charges represent the cost of internal transfer of crude since CBU is a part of Chennai refinery.

Secondly, these charges have been factored into the analysis at a later stage while discussing the premiums and discounts and including them in the price options will amount to double counting.

The difference between Option A and Option C is $3.29/bbl, which then represents the negotiating margin for ONGC and the refineries.

Premium factors for ONGC

Security of supplies

As elaborated earlier, the risk of disruption in the supply of imported crude is much higher than that for domestic crude. Thus, if a refinery chooses to increase its dependence on imports by replacing indigenous crude with imported crude, it is taking an extra risk of running at lower capacity utilisation. If CBU decides to import 434 TMT of crude to replace Cauvery basin crude, in the event of a supply disruption, it can face an increase in the fixed cost to the extent of Rs 0.919/MT ($0.002/bbl) following the methodology enumerated in Chapter 10. Thus, ONGC can command a premium to this extent. The detailed calculations are at Annexure 11.2.

Augmentation of infrastructure for imports

The CBU refinery takes 54 TMT of imported crudes via road from the Manali (Chennai) refinery. The port occupancy at the Chennai port (Table 10.5) is around 60% which does not suggests that it will be needing a any augmentation to import an additional quantity of 434 TMT.

However, one major constraint is the high cost of transporting the crude from Chennai to Narimanam via road. The cost of transportation along the road is 0.85 Rs/MT/Km[a]. Thus, if the CBU decides to replace the Cauvery basin crude with imported crude, it will have to take this extra quantity through road. The current estimated costs of transporting 54 TMT is Rs 15 million which will rise to Rs 138 million if it takes 434 TMT of imported crude. Thus, CBU has to incur Rs 283/MT as the cost of transporting the crude from Chennai to Panangudi.

Costs of international procurement

As mentioned earlier, there are certain adjutant costs of imports like LC charges etc. which an importing entity would have to incur. Thus, a shift to domestic crude will save these costs for the refineries. These factors have been analysed on the similar lines as previous chapters.

Letter of credit charges

As mentioned in the earlier chapters, refineries taking the imported crude for the first time may have to pay higher LC charges on the basis of their untested financial position.

[a] Data from OCC

The Oil Co-ordination Committee uses a norm of 0.3% as the LC charges on imports. If CBU is required to pay even 0.1% higher LC charges, its cost of imports will rise by Rs 6.69/MT ($ 0.019/bbl). Thus, ONGC can ask for a premium to this extent on this account.

Foreign Exchange risks

There might be difference between the rate at which the deal for imported crude is decided and the rate at which the sale actually takes place. This difference may arise either due to change in the price of the crude or just due to fluctuations in the exchange rate since all imports are on dollar basis. Thus, a refinery is exposed to exchange rate risk on the imported crude. For CBU refinery, a 1% depreciation in rupee will cause a rise of Rs 74.44/MT ($0.220/bbl) for the month of January 2002 on import of Arab Light. Thus, ONGC is in a position to charge a premium to this extent.

Freight diseconomies

The entire quantity of 54 TMT of imported crude processed by CBU is transported via road from the Chennai refinery. Chennai refinery processes about 4.6 MMT of crude every year. Bringing an additional quantity of 0.434 MMT of crude for CBU should not pose any problem for CPCL since the Chennai port can handle a maximum ship size of 140,000 TMT. Thus, ONGC cannot ask for a premium from CBU on this account.

Discount factor for ONGC

As explained above, ONGC has got no choice but to continue selling its Cauvery basin crude to the CBU refinery. This means that ONGC is not in a position to bargain for import parity price for its crude. Thus, the only discount factor for ONGC is that it will have to accept the FOB as the pricing base for crudes of this region.

Summary Table

Table 11.2 Summary of premiums for Cauvery basin

	Rs/MT	$/bbl
Premium factors for ONGC		
Augmentation of facilities for imports	283	0.839
Cost of international procurement		
Letter of credit charges	6.69	0.020
Exchange rate risks	74.44	0.221
Total	365.049	1.083
Net premium	365.049	1.083

Strategic option

The above discussion points to the fact that ONGC may not get the import parity price for its crude due to prohibitive costs of moving crude to alternate refineries. It may have to negotiate for FOB price only.

Applying this premium to the two FOB options for setting the base price, the following surpluses emerge. The detailed calculations are at Annexure 11.1.

Table 11.3 Surplus for ONGC from Cauvery field ($/bbl)

Refinery	Option A	Option B
CBU	1.48	1.97

This table shows that if ONGC were to get the FOB price for its crude, then even if it gets the full premium as estimated above, it will find it difficult to generate enough surplus from this region.

Under Option B, the surplus left is $ 1.97/bbl which is $ 0.33/bbl less than the surplus of $ 2.3/bbl required by ONGC to fund its exploration activities. Thus, ONGC should try to negotiate at least that price at which $ 0.33/bbl higher than the price under Option D. This is not a big amount considering that the pricing on FOB would save the refinery the freight from Middle East to East Coast India.

12 Strategy for marketing Krishna-Godavari crude

This chapter outlines the various considerations that would be important in negotiating the price of Krishna-Godavari (KG) crude.

Out of the annual production of 0.30 million tonnes, about 0.05 million tonnes is processed by ONGC itself in its Tatipaka refinery, commissioned last year, and the rest, 0.25 million tonnes, goes to the Vizag refinery of HPCL.

From the production fields, the crude is first moved to Suryasayanam via road tankers and from thereon it is pumped to Ravva crude fields where it is mixed with the Ravva crude and moved to Vizag refinery via ocean tankers. The cost of transporting the crude to the Ravva field is Rs 200/MT. In addition, a Ravva processing charge at the rate of Rs 180/MT is also levied, taking the total cost of transportation to the port as Rs 380/MT. The transportation cost incurred by ONGC in moving this crude is high because of the small and scattered fields marking the KG basin which means that crude moves via road tankers raising the transportation cost. This was the primary reason behind setting up a small refinery in the region to get value-added products like Naphtha, Kerosene and Diesel. It could be thus concluded that the prospects of this crude moving to the other two refineries in the region – Haldia and Chennai – are very bleak.

The total installed capacity of the Vizag refinery is 7.5 MMTPA. The total crude throughput of the refinery in the year 2000-01 was 6.4 MMTPA which means that KG crude fulfils only 3.9% of the refinery's demand for crude. The Vizag refinery takes 2.5 million tonnes of Ravva crude and 3.8 million tonnes of imported crudes. Thus, apart from the fact that Vizag refinery is not dependent on the KG crude for its processing needs, it also has some other options for sourcing the crude. It therefore seems that the Vizag refinery is in an advantageous position as far as KG crude is concerned.

Moreover, crude oil production from the KG field is projected to decline during the Xth plan period as shown in the table below.

Table 12.1 Projected production for the Xth plan period (million tonnes)

	2002-03	2003-04	2004-05	2005-06	2006-07
Krishna-Godavari	0.213	0.176	0.15	0.13	0.115

It can be thus concluded that, with respect to the KG crude, it is the refinery that is in a better negotiating situation.

Base price

As elaborated in chapter 8, there are four options ONGC faces while negotiating the basic price of the crude. These are reproduced here. The detailed calculations showing the price receivable by ONGC under each option are at Annexure 12.1.

- **Option A** – Price the crude at FOB of the benchmarked crude at custody transfer point but pay the sales tax on the crude.
- **Option B** – Price the crude at FOB of the benchmarked crude at custody transfer point.
- **Option C** – Price the crude at the Import Parity Price (IPP) of the benchmarked crude at the custody transfer point.
- **Option D** – Price the crude at the IPP of the benchmarked crude at the custody transfer point but pay the sales tax on crude.

As detailed in chapter 4, the nearest international crude in terms of physical qualities is the Arab Light.

As shown in Annexure 12.1, the difference between the price received by ONGC from the refinery under the FOB option and the import parity option is \$3.36/bbl, which then represents the negotiating room for each party.

The custody transfer point for the KG crude is the Ravva field where the crude is mixed with the Ravva crude prior to moving to the Vizag refinery.

Premium factors for ONGC

Security of supplies

As noted in earlier chapters, the premium accorded to the crude due to this factor was because of the high risk associated with the imported crude supplies due to long haul and political instability of the major producing countries. High percentage of indigenous crude lowers this risk for the refinery.

However, this factor does not seem to be of much relevance for the crude which forms only about 4% of the total throughput and which has a indigenous competitor in Ravva crude forming about 40% of the throughput. Thus, no premium can be accorded to KG crude on this account.

Augmentation of infrastructure for imports

Imports account for about 59% of the total throughput of the Vizag refinery. Crude is imported via the Vizag port jetty, which in the year 1999-2000 had a occupancy of 83-78%, which is quite high. Nevertheless, replacing the KG crude with imported crude should not pose any problem for the refinery. In the event of complete replacement, the imported crudes would rise by about 6.5% for which the high port occupancy should not be a bottleneck.

Cost of international crude procurement

This factor should also be analysed in light of the already high percentage of the imported crudes in the Vizag refinery's crude mix.

Letter of credit charges

Refineries importing the crude for the first time may be required to pay a higher LC charges due to lack of high creditworthiness in the international oil market. But again, this argument does not apply to the Vizag refinery in this context since it is already importing a large quantity of crude and importing an additional amount of 0.25 million tonnes would not raise the import cost by much.

Foreign exchange risks

These risks arise because of the possibility of depreciation in the domestic currency with respect to the currency, in which the payment has to be made, which is usually US dollar. Thus, if the imports form a high percentage of the crude mix for any refinery, it may experience volatility in refinery margins unless it has hedged its foreign exchange requirement.

Accordingly, the Vizag refinery is already exposed to a high foreign exchange risk. Importing additional crude to replace the KG crude will not increase this risk by much since the quantity is very small. Moreover, it can't be positively said that KG crude can be replaced only by imported crude in the light of the presence of Ravva crude field. Thus, premium can't be claimed by ONGC on this account also.

Freight diseconomies

In the regulated scenario, Indian Oil Corporation (IOC), which was the sole canalising agency for crude imports, was importing it on behalf of Vizag refinery. Now, after the dismantling of APM, HPCL has decided to import its requirement on its own. The combined requirement of the two refineries of HPCL – Mumbai

and Vizag is 7.24 MMTPA. The quantity of KG crude is just 3.45% of this quantity, which in any case will be imported. Thus, bringing this additional quantity of crude should not pose any problem for the refinery.

Discount factors for ONGC

BS&W in KG crude

As provided by ONGC, the level of BS&W is 0.3%, which is much above the internationally accepted level of 0.02%. Any crude with BS&W higher than 0.02% is discounted in the international market. In a deregulated scenario, the refineries, paying an internationally linked crude price, will demand international standard crude. Thus, ONGC will possibly have to yield a discount to the refinery on this account.

As submitted by ONGC, it takes around Rs 100 million to desalt 1 MMT of crude. Thus, the annutised capital cost of desalting the KG crude will be Rs 15.53/MT. This has been used as the proxy discount that ONGC may have to yield to the refinery. The detailed calculations are at Annexure 12.2.

Summary table

As the above analysis shows, there are no sufficient reasons for ONGC to get a premium over and above the base price. In fact, the KG crude is likely to get discounted due to the high level of BS&W in it. Thus, the net discount that ONGC may have to yield is as follows.

Table 12.2 Summary of discount for KG basin crude

Discount factors for ONGC	Rs/MT	$/bbl
BS&W in KG crude	15 53	0 046
Total discount	15.53	0.046
Net discount	15.53	0.046

Strategic option

As is mentioned earlier in the chapter, there is no refinery, either in India or abroad, can process the KG crude, though it is a light and sweet crude, primarily due to its low production quantity. Thus, ONGC has got no option but to sell this crude to the Vizag refinery. Vizag, on the other hand, has two other sources of crude procurement, one of which is indigenous and is contributing significant quantity. Thus, it is very unlikely that ONGC will get import parity price for KG crude. But at the same time, there is no reason why ONGC should get anything

less than the FOB of the benchmarked crude. Thus, FOB represents the minimum base price for ONGC to negotiate for.

If the base price is indeed set at FOB, then the surplus left for ONGC after meeting all the claims like tax, cess, and other direct and indirect costs is shown below. The detailed calculations for all the four options are at Annexure 12.1.

Table 12.3 Surplus for ONGC from KG basin ($/bbl)

Refinery	Option A	Option B
Vizag refinery	0.75	1.24

As this table shows, this pricing option is not sustainable for ONGC. It needs at least $2.3/bbl to fund its commitment in E&P but this field will not generate enough surplus for the same. The lowest gap between surplus generated from these options and exploration commitment is $1.06/bbl. Thus, ONGC should negotiate for at least that price which enhances the surplus by $1.06/bbl. This is not a big amount if the crude is priced at FOB since then the refinery will be saving all the transportation charges and other charges incurred in importing the crude and given the fact that there is a margin of $3.36/bbl between FOB and Import parity pricing.

13 Strategy for marketing North-Eastern crudes

This chapter outlines the considerations that are important in determining the price of the North Eastern crudes.

There are two main collection centres in the northeastern region: Jorhat and Moran. These two supply crude oil to four refineries: Barauni, Guwahati, Bongaigaon and Numaligarh refinery. Of these, Bongaigaon consumed the highest quantity in the year 2000-01 followed by Guwahati and Barauni. Numaligarh consumes a very small quantity of ONGC crudes.

Oil India Limited (OIL) is the other crude producer in this region and supplies crude oil to all refineries in this region, except Haldia refinery, which takes only the imported crudes.

The consumption of indigenous and imported crudes by various refineries for the year 2000-01 is shown below.

Table 13.1 Crude oil consumption pattern for Northeast refineries (thousand tonnes)

Refineries	Total throughput	ONGC crude	OIL crude	Imported
Barauni	3122	300	402	2420
Haldia	3875	-	-	3875
Guwahati	707	310	397	-
Digboi	679	-	679	-
Bongaigaon	1490	552	856	82
Numaligarh	1451	20	1431	
Total	11324	1182	3765	6377

Source. OCC

As shown above, Haldia refinery is processing only the imported crude. Moreover, since there is no infrastructure to move crude from North East to Haldia, Haldia is not a potential customer for North Eastern crudes.

Digboi refinery, however, is a potential customer though it is not processing the ONGC crudes currently since there is a pipeline carrying the crude from Moran CTF to Digboi refinery.

Table 13.1 also shows that out of total indigenous crude sales of 4.947 MMT, ONGC accounts for only 23% whereas OIL accounts for the remaining 76%. And in so far as all the crude supply pipelines are also owned by OIL, ONGC does not seem to have much bargaining power in the Northeast.

Moreover, as the table below shows, the projected production from the Assam region is expected to decline in the tenth plan period.

Table 13.2 Projected production from North East region (MMT)

	2002/3	2003/4	2004/5	2005/6	2006/7
Production	2.013	2.057	2 066	2 054	2.004

There are two factors that determine the options available to ONGC.

1) Infrastructure – There is no physical infrastructure at the disposal of ONGC to move the crude to the port for exports or for coastal movement within India. Even within the Northeast, all the supply pipelines are owned by OIL.
2) Production – The production of ONGC fields is very small compared to OIL and moreover it is declining.

This shows that ONGC has got no option but to sell its crudes to refineries in the region.

On the other hand, OIL being a major producer in the region, refineries have an alternate option for crude procurement in OIL. With a volume of only 1 MMTPA, there isn't much bargaining power with ONGC.

Basic price

As elaborated in chapter 10, there are four options ONGC faces while negotiating the basic price of the crude. These are reproduced below. The detailed calculations are at Annexure 13.1. As mentioned in Chapter 4, the international crude to which the North Eastern crudes have been benchmarked is Bonny Light from Nigeria.

- **Option A** – Price the crude at FOB of the benchmarked crude at custody transfer point but pays the sales tax on the crude.
- **Option B** – Price the crude at FOB of the benchmarked crude at custody transfer point.
- **Option C** – Price the crude at the Import Parity Price (IPP) of the benchmarked crude at the custody transfer point.
- **Option D** – Price the crude at the IPP of the benchmarked crude at the custody transfer point but pays the sales tax on crude.

The calculations for import parity prices have been done taking Haldia port as the discharge port and excludes the transportation costs of moving the crude from Haldia to respective refineries because it will be negotiated as to who will bear these costs.

The difference in the price realisable by ONGC under the FOB and IPP options is \$4.92/bbl. This represents the negotiating margin for ONGC and for the refineries.

Following the format in the previous chapters discussed below are the potential factors that could earn ONGC some premium.

Premium factors for ONGC

Alternative options for refineries and ONGC

The main factor that has to be considered in pricing the Assam crudes is the options that the refineries and the ONGC have. Three refineries in the region- Haldia, Barauni and Bongaigaon are already taking imported crudes while Digboi, Numaligarh and Guwahati are dependent only on the indigenous crudes. The imported crude to Barauni refinery is transported via the Haldia-Barauni pipeline, which is owned by IOC and has the capacity of 4.2 MMTPA. Given the installed capacity of Barauni refinery as 4.2 MMTPA and the average throughput of 3.1 MMTPA, the pipeline capacity is not a constraint.

The average occupancy at the Haldia port during the year 2000-01 was 63-69% (table 6.12). Given the total crude oil import volume at the port of 6.2 MMTPA, importing an additional 0.3 MMTPA (to replace the ONGC crude) should not pose any problem for the Barauni refinery.

Bongaigaon refinery processed around 0.082 MMT of imported crude in the year 2000-01. The imported crude to Bongaigaon refinery is transported via the Barauni-Bongaigaon pipeline with the capacity of 3 MMTPA. Thus, this pipeline is not a bottleneck for BRPL. The nearest port for BRPL is Haldia and as mentioned above, the port occupancy does not rule out additional imports of 0.082 MMTPA.

Thus, infrastructural bottlenecks are not a hindrance in these refineries taking in extra imported crude to replace the ONGC crude.

Digboi and Numaligarh are heavily dependent on the OIL's crude and hence the chances of their importing the crude to replace the ONGC crude are very less.

Guwahati refinery is dependent on ONGC for 43.84% of its crude throughput. Thus, it can be assumed to be dependent on ONGC for crude throughput. But it also accounts for 51.6% of total ONGC crude sales along with Barauni refinery (which is also owned by the same company, IOC). Thus, the possibility of ONGC terminating the supply contract with IOC for this region is

very less. Thus, Guwahati is also not on a weak footing with respect to ONGC for sourcing its crude.

Security of Supplies

This is as much an issue with those refineries which are taking the imported crudes as it is with those which are processing only the domestic crudes. For the former, dependence on imported crude will expose them to risk of disruption in supplies whereas for the latter, it represents the avoided cost of risk of supply due to their intake of domestic crude, in the absence of which they will be forced to either operate at lower capacity or depend on imported crudes.

However, there are two factors that may have an opposite effect. Firstly, OIL is the major producer in the region and can supply to all the refineries. Secondly, out of total throughput of 11 MMTPA for the region, ONGC's 1 MMTPA is cannot be perceived to have any substantial effect on the security of supplies in the region. As such the region is accounting for only 8.5% of the total imported crudes in the country. So a disruption of 62.21 MMT would not have a huge impact on the region.

Cost of international procurement

As mentioned earlier, the less established refineries may have to pay a higher LC charge while importing crude. Just 0.1% increase in LC charges will raise the cost of imports for the refineries by Rs 7.43/MT ($0.022/bbl). Thus, ONGC can charge a premium to this extent.

However, Digboi cannot be expected to pay this premium because it is processing only the OIL's crude. OIL also accounts for 98% of the Numaligarh refinery's crude throughput and hence the refinery's need for international crude is very less. Also, Barauni and Guwahati refineries, being a part of IOC which is a Fortune 500 company, may not pay a higher LC charge on imports. And since Bongaigaon is importing only 0.082 MMTPA of crude, this factor is not very important for it also.

Thus this factor is not important for negotiations in this region.

Freight diseconomies

In the regulated era, IOC was the sole canalising agency for the refineries taking imported crude. Due to this large volume, it was able to economise on the freight. However, if the refineries decide to import individually, the requirement may not be as much as to fill a VLCC tanker and hence they will bring crude in smaller vessels which would mean higher freight.

However, an analysis of the imported crude requirement of the refineries shows that this factor is not very important.

The Barauni refinery is already taking 2.4 MMTPA of imported crude and taking an additional quantity of 0.3 MMTPA would not raise the import cost on any account.

The imported crude requirement of the Bongaigaon refinery is only 0.082 MMTPA , which can be clubbed with Barauni refinery.

Digboi does not process any imported crude and hence will be not be affected. Numaligarh takes only 1.3% of its crude throughput from ONGC and hence is in a confortable position. The Guwahati refinery takes 0.310 MMTPA of ONGC crude and if it decides to replace it by imported crudes, it can be easily clubbed with Barauni and Haldia (both owned by IOC) and hence would not necessitate any additional costs of imports for the refinery.

Thus, there will no premium on this account for any refinery.

However, there is one factor that may force ONGC to give a discount on its crude. This is discussed below.

Discount factor for ONGC

High BS&W of the Assam crudes

The average BS&W in the Assam crudes is 0.2% which is higher than the international standard of 0.02%. ONGC would either have to bring the crude to the international standard before dispatching it to the refineries or it would have to accept a discount to the extent of the cost which has to be incurred in doing so. As provided by ONGC, it costs about Rs 100 million to desalt 1 MMT of crude. Thus the annutised cost of desalting 2 MMT of crude can be estimated as Rs 16.47/MT (0.048 $/bbl). The detailed calculation is at Annexure 13.2.

Summary table

The above analysis shows that there is no strong reason for refineries to yield a premium to ONGC for its crude. However, high BS&W in the crude will probably force ONGC to give a discount.

Table 13.3 Summary of discounts for NE crudes

	Unit	Barauni	Guwahati	Digboi	BRPL	NRL
Discount factors for ONGC						
BS&W problem	Rs/MT	16.47	16.47	16.47	16.47	16.47
Total Discount	Rs/MT	16.47	16.47	16.47	16.47	16.47
Average Net Discount	Rs/MT	16.47	16.47	16.47	16.47	16.47
Average Net Discount	$/bbl	0.048	0.048	0.048	0.048	0.048

Thus, for the north-eastern refineries, ONGC may have to yield a discount of Rs 16.47/MT or 0.048 $/bbl.

Strategy for North Eastern crudes

Given the fact that ONGC does not have any alternate option to sell its crude and given the fact that ONGC's crudes are not of international quality, it will be difficult for it to demand import parity price for its crude. The refineries are in a better position to source the crude either from OIL or take the imported crude and hence will not give import parity price to ONGC. Thus, out of the four pricing options mentioned earlier, only two are possible – those based on FOB.

The surplus left for ONGC under the two pricing options is shown below. The detailed calculations are at Annexure 13.1.

Table 13.4 Surplus for ONGC from NE crudes ($/bbl)

Refinery	Option A	Option B
Barauni	1.26	1.77
BRPL	1.26	1.77
Guwahati	1.26	1.77
NRL	1.26	1.77
Digboi	1.26	1.77

This table shows that surplus generated in Northeast may not be enough if the pricing is done on FOB basis.

However, if ONGC can negotiate for an additional $ 0.53/bbl under Option B, it can make the required surplus of $ 2.3/bbl. This amount of $ 0.53/bbl is not high considering the fact that pricing crude on FOB effectively saves the freight from Nigeria to East Coast India.

PART 2
Natural Gas

14 Marketing strategy for natural gas

Overview of the Indian gas industry

Although the use of natural gas has increased rapidly, it accounts for only around 11% of the primary energy use in India. Till the late 1980s the demand lagged behind the production potential mainly because of lack of infrastructure. However, in the 90's, the demand has exceeded the supply. Gas reserves and production trends in India are presented in Annexure 14.1.

In view of the shortage of gas production and supply compared to demand, the government of India allocates gas to all consumers. The current gas allocation is 105.90 MMCMD whereas the domestic gas production in 1999-00 had been only about 78 MMCMD[a].

The power and fertiliser sectors have been allocated most of the gas as shown in the Table below.

Table 14.1 Sector-wise gas allocations (MMCMD)

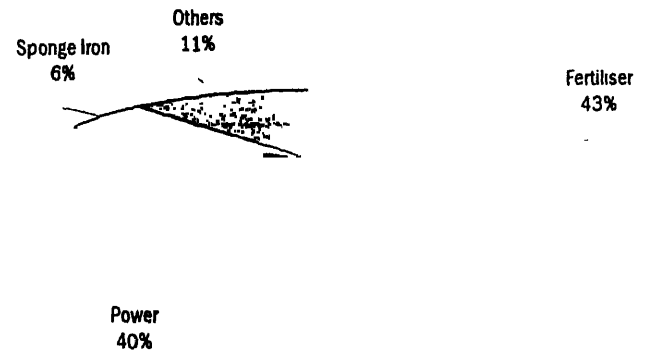
Sector	Allocation (MMCMD)
Power	42.76
Fertiliser	26.35
Others	36.79
Total	**105.90**

Source. GAIL

The power and fertiliser sectors together consume about 80% of the gas today. The sponge iron units consume another 10%. The balance goes to industrial units where it replaces mostly fuel oil and some LPG. Gas is also supplied to the residential and the commercial sectors in Mumbai, Delhi and a few towns of Gujarat, Assam and Tripura. This gas is used for cooking only, as space heating is not required. The daily requirement of households is only around 1 cum. With such low requirements and the subsidy on domestic LPG, the demand from this sector will continue to be low. The use of CNG in lieu of petrol has been popular in Mumbai and Delhi. Gas use by various industries has been discussed further in Annexure 14.1.

[a] Source. Basic Statistics on Indian Petroleum and Natural Gas, 1999-2000, MoPNG

Figure 14.1 Sectoral gas sales (1998/99)



Source. GAIL

Area wise and sector wise use of natural gas in 1998/99 is shown in Table below:

Table 14.2 Gas utilisation: 1998/99 (MMCMD)

Area	Fertiliser	Power	Sponge Iron	Others	Total
Western Offshore					
Uran	5.0	4.7	1.4	0.7	11.8
HBJ	13.0	9.1	-	2.5	24.6
Hazira	2.7	-	-2.0	1.2	5.9
Western Onshore	1.2	4.2	-	1.4	6.8
Rajasthan	-	0.4	-	-	0.4
K. G. Basin	1.7	2.2	-	0.1	4.0
Assam	0.0	0.4	-	0.1	0.6
Tripura	-	0.8	-	0.0	0.8
Cauvery Basin	-	0.0	-	0.1	0.1
Total	**23.6**	**21.9**	**3.5**	**6.1**	**55.1**

Source. GAIL

According to Hydrocarbon Vision 2025, the power and fertiliser sectors would dominate gas consumption and the demand would build up as shown below.

Table 14.3 Total gas demand (MMCMD)

	1998/99	2001/02	2006/07	2011/12	2024/25
Power					
Scenario 1*	22	40	67	90	153
Scenario 2**	22	67	119	168	208
Fertilizer	24	54	66	83	105
Others#					
Scenario 1	9	23	33	43	64
Scenario 2	9	30	46	63	78
Total					
Scenario 1	55	117	166	216	322
Scenario 2	55	151	231	313	391

* gas at $4/MMBtu

** gas at $3/MMBtu

\# other sectors account for 20% of total demand in 2002 and thereafter

Our own estimates of gas demand are more conservative, as shown in the next section.

ONGC draws up long term profiles of gas production every year. The gas production projections by ONGC is shown in table below.

Table 14.4 Projected gas production by ONGC (MMCMD)

	2002-03	2003-04	2004-05	2005-06	2006-07
Gas (MMCMD)[a]	50.48	48.88	46.05	46.51	47.04

Source. ONGC

Current projections show that the total gas production would decline steadily until the Bombay High gas cap is brought into production. This is expected between the years 2015 and 2020. The declining production profile coupled with the projection of rising demand shows a widening demand-supply gap. This implies that exploration efforts need to be stepped up and the feasibility of importing gas from the neighbouring countries examined seriously. The initiatives and prospects for exploration and option for importing gas through pipelines have been described in Annexure 14.1. Various LNG import projects have simultaneously been planned in India. The status of these projects has been discussed in later sections of this chapter.

[a] Does not include production from joint venture fields

Gas supply sector organisation

The gas supply sector in India is dominated by public sector enterprises under the administrative control of the Ministry of Petroleum. Ninety percent of the gas is produced by two state owned oil companies, the Oil and Natural Gas Corporation (ONGC) and Oil India Limited (OIL). The balance comes mostly from the medium sized fields - Panna, Mukta and Tapti in the western offshore and Ravva off the Andhra coast - operated by joint ventures of ONGC. Several small gas fields operated in the private sector are also producing gas but their production does not add up to much.

The gas produced by ONGC is marketed by GAIL except gas from isolated marginal fields marketed direct by ONGC. OIL, which operates mainly in Assam and also in Rajasthan sells gas mainly through its own arrangements and partly through GAIL. The gas from Panna-Mukta-Tapti and Ravva is bought by GAIL on behalf of the government. All of this gas is sold only to consumers who are allocated gas by the Government of India. The private operators of small gas fields are free to select their customers. The gas price to be charged by ONGC and OIL and the transportation charges along the HBJ pipeline of GAIL are fixed by the government. Gas from private fields is sold at negotiated prices.

The gas industry infrastructure

The Hazira-Bijaipur-Jagdishpur (HBJ) gas pipeline network is the major gas transmission line in India, owned and operated by the Gas Authority of India Limited (GAIL). It starts at Hazira in Gujarat and passes over Rajasthan, Madhya Pradesh, Uttar Pradesh into Haryana. It is 2300 km long with a capacity of 33.4 MMCMD. Spur lines at various points in Gujarat, Rajasthan, Uttar Pradesh, Delhi and Haryana feed power plants, fertiliser plants and industries.

Wet gas from the offshore South Bassein field off the coast of Maharashtra, is fed by 216 km sub-sea lines of 36" and 42" diameter to ONGC's sweetening and fractional separation plant at Hazira. The gas handling capacity at the Hazira terminal is 41 MMCMD.

With several LNG terminals being planned on the west coast of India, GAIL plans an investment of Rs. 30 billion to expand the HBJ capacity to 60 MMCMD by 2003. GAIL also plans to extend the HBJ pipeline to Ludhiana in Punjab.

In addition to the HBJ pipeline, there are regional gas grids of varying sizes in the states of Gujarat, Andhra Pradesh, Assam, Maharashtra, Rajasthan, Tamil Nadu and Tripura. Most of these regional pipelines (about 725 km) were constructed and operated by ONGC but ownership and operation of these gas grids were passed on to GAIL in the nineties. The present grid capacity is based on the gas availability from the producing areas as well as the outlook for future gas productio In view of the increased availability of gas in the KG basin, GAIL has announced plans for augmentin pipeline capacity in Andhra Pradesh.

Distribution

The Mahanagar Gas Limited, a joint venture between GAIL and British Gas is supplying gas to aroun 50,000 houses in Mumbai as well as small industrial and commercial units and CNG filling stations. The Indraprastha Gas Limited, a joint venture of GAIL and BPCL is supplying gas in Delhi to around 1000 houses and 80 CNG stations. At the instance of the Supreme Court, the fleet of buses, taxis an rickshaws in Delhi is being converted to CNG. The other cities with natural gas distribution systems are Vadodara, Surat and Ankleshwar in Gujarat and a few towns in Assam and Tripura in the north-east.

The objective of the marketing strategy of gas produced by ONGC is to maximise the netback to ONGC from selling gas. This can generally be achieved by selling gas to the market segment consisting of the high imputed value sectors like power generation, fertilisers, captive power, etc. at prices approaching their opportunity costs. Imputed value of gas at any location is the maximum payable for gas if it has to replace the cheapest alternative fuel at that particular location. This is the way gas is sold in mature markets all over the world. It is interesting to note that ONGC priced gas on this basis in Maharashtra in 1978 and extended it to Gujarat in 1982. This principle of pricing was challenged by some consumers in the Supreme Court but the court upheld the prices. Since 1987, however, gas has been sold at uniform prices to all customers at the same location. The price is now linked to international prices of fuel oil. The pricing policy of domestic gas and issues in sales contracts between GAIL and consumers have been discussed in Annexure 14.1.

The steps that have been followed to formulate the marketing strategy for ONGC gas are as follows:

- the state-wise gas demand has been estimated till 2006/7 for power, fertiliser and industrial units
- imputed values for each industry type has been evaluated at select locations
- gas demand that can be captured at each imputed value has been assessed
- the various pricing options for ONGC gas has been discussed and strategy to be adopted to obtain the best deal in each case has been framed.

Estimation of gas demand

Gas demand has been estimated till 2006/7. As power generation and urea production consume 80% of the gas available, these sectors have been examined closely for projecting the gas demand. Gas demand from glass, paper and cement industries have also been projected. Captive generation is a promising area for gas use and this area has also been examined. Gas use in city distribution is likely to be limited and can be estimated only through detailed surveys. We have accordingly not looked at this sector.

TERI estimates of sector-wise gas demand is shown in Table below.

Table 14.5 Total gas demand (MMCMD)

	Existing	2006/7
Power	49.37	71.79
Fertiliser	40.22	40.22
Cement	4.84	6.87
Paper and pulp	3.35	5.04
Glass	1.87	2.65
Total Industries *	10.06	14.56
Captive	5.78	10.36
Total	105.43	136.93

* Does not include industries other than cement, paper and glass.

The detailed methodology for gas demand estimations, state-wise and sector-wise is shown in Annexure 14.2.

The demand numbers above do not refer to any price level. To find the demand at different prices, we develop the imputed values at different locations.

Imputed values

Imputed value of gas is the price of gas at which the cost of generation or production in a gas based plant equals the cost of generation/production using an alternative fuel, at a particular location. Thus imputed value indicates the maximum price for gas at which it is competitive with the cheapest alternative fuel. The methodology used has been illustrated in Table below.

Table 14.6 Methodology for calculating imputed value of gas

Cost of generation/production	Gas based	Competing technology
Capital cost	A	c
Operation and maintenance cost	b	d
Fuel cost	X (unknown)	e
Total cost		f = c + d + e
Imputed value of gas		X = f - a - b

Power generation

The imputed values for power generation have been computed against domestic coal. The detailed methodology is provided in Annexure 14.3. The locations selected are places where power projects are proposed to be set up.

Table 14.7 Imputed values of gas in power generation ($/MMBtu)

Location	Domestic coal*
Bawana	4.70
Faridabad	4.62
Hisar	4.99
Doraha	5.03

Location	Domestic coal*
Bhatinda	5.20
Govindwal	5.09
Dholpur	4.32
Suratgarh	5.35
Anta	4.36
Kawas	5.03
Ghandhar	4.93
Mundra	5.03
Pipavav	5.26
Auraiya	4.40
Unchahar	4.07
Jawaharpur	4.44
Anpara	3.79
Partapur	5.17
Bhander	4.23
Rosa	4.79
Sipat	2.92
Korba	2.97
Vindhyachal	3.98
Raigarh	2.97
Trombay	4.75
Chandrapur	4.03
Vizag	3.66
Raichur	5.46
Chennai	4.41
Kayamkulam	5.57
Guwahati	4.78

* at locations within 1500 km of domestic coal fields, coal without washing has been considered otherwise washed coal has been considered as the suitable alternative fuel

Urea production

Imputed values of gas in urea production have been estimated against imported urea at a long term average cif price of $150/MT. The landed cost of imported urea at the Indian port with a cif price of $ 150/MT, an exchange rate of Rs 46 per US dollar and 25% import duty[a], the landed cost at the Indian port would be Rs 8625/MT.

[a] Currently there is no import duty on imported urea

Table 14.8 Imputed values of gas against urea imports at cif $150/MT

Location	Imputed values ($/MMBtu)	
	New plants	Expansion units
Babrala	4.51	4.99
Jagdishpur	4.65	5.13
Shahjahanpur	4.71	5.19
Gorakhpur	4.70	5.18
Hazira	3.78	4.27
Nangal	4.49	4.97
Thal	3.86	4.35
Kota	4.27	4.76
Panki	4.58	5.07
Phulpur	4.65	5.13
Barauni	4.09	4.58
Durgapur	3.86	4.35
Nellore	4.04	4.52
Goa	3.78	4.27
Kochi	3.78	4.27
Kakinada	3.78	4.27
Vizag	3.78	4.27
Chennai	3.78	4.27
Mangalore	3.78	4.27
Tuticorin	3.78	4 27

The imputed value against the urea price of Rs 7500/MT recommended by the Expenditure Reforms Commission (ERC) has also been computed.

The ERC has recommended that Rs 1,900/MT be allowed as concession to new units based on LNG while the farmgate price paid by the consumer is pegged at Rs 7000/ MT. In that case, the producer would receive a net price of Rs. 8,600/MT after deducting Rs 300/ MT as the marketing cost. The imputed value of gas against this producer price is $ 4.24/MMBtu for an expansion of a gas based plant and $4.85/MMBtu for conversion of naphtha based plant to a gas based plant.

Details of imputed values of gas in urea production is discussed in Annexure 14.3.

LNG vs Naphtha in urea production

Any urea producer wishing to change over to LNG would have to enter into a long-term contact (15-20 years) with LNG suppliers. In a situation of naphtha surplus in the country, the question remains if future naphtha prices could drop to such low levels as to become competitive with the LNG option. If such were the case, urea producers should stay with naphtha rather than opting for LNG. To examine such possibility, we have calculated naphtha export parity prices at three locations: Kota, Panki and Phulpur shown in Table 14.9. For comparison, naphtha import parity prices have also been presented. Detailed calculations of export parity and import parity prices are given in Annexure 14.3.

Tables 14.9 Naphtha export parity and import parity price

Locations	Naphtha export parity price ($/MT)	Naphtha import parity price ($/MT)
Kota	200	281
Panki	198	293
Phulpur	208	286

The imputed values of gas against the above naphtha prices at Kota, Panki and Phulpur are presented in the Table below with details in Annexure 14.3.

Table 14.10 Imputed values of gas against naphtha

Locations	Imputed value against naphtha export parity price ($/MMBtu)	Imputed value against naphtha import parity price ($/MMBtu)
Kota	4.70	6.54
Panki	4.66	6.79
Phulpur	4.87	6.64

Industries and captive generation

Imputed values for cement and paper industry have been calculated at the identified clusters against domestic coal. For the glass industry, imputed values have been calculated against LPG ex-Koyali, Mathura, Mumbai and Vizag. For captive generation, imputed values have been calculated against naphtha ex-Koyali, Mathura, Mumbai and Vizag. . The methodology is provided in Annexure 14.3.

Imputed values of gas for industries and captive generation have been computed on calorie equivalence. The Table below presents the imputed values.

Table 14.11 Imputed values for industries and captive generation

Location	Imputed values ($/MMBtu)
Cement and paper industry: against domestic coal	
Sikka	2.35
Kota	1.79
Delhi	1.99
Pipavav	2.36
Surat	2.16
Satna	1.36
Amritsar	2.24
Chandrapur	1.64
Malkhed	2.01
Tadipatri	2.19
Glass industry and city distribution: against LPG	
Ex-Koyali	10.10
Ex-Mathura	10.56
Ex-Mumbai	9.93
Ex-Vizag	9.80
Captive generation: against naphtha	
Ex-Koyali	7.29
Ex-Mathura	7.89
Ex-Mumbai	7.10
Ex-Vizag	7.12

Industry in Gujarat is now paying a gas price of Rs 2850/thousand cubic metres which equals \$1.56/MMBtu. In addition they pay royalty of 10% (\$0.16/MMBtu) and transport charges depending on location. The domestic gas price is due for a revision and may soon exceed \$3/MMBtu. The consumers will not surrender their allocations and change to coal. Indications are that most of them would continue to use gas. The imputed values of \$1.83 - 2.39/MMBtu calculated for industrial units, therefore, underestimates the price they would be willing to pay. It is possible for cement units to reduce energy consumption from 930 kcals/kg, assumed by us in computing the imputed value, to 700 kcals/kg. There are additional benefits in terms of savings in power consumption, refractory consumption and clinker quality in changing over to gas. Cement producers should be able to pay between \$2.9–3.6 / MMBtu depending on location.

Having projected the gas demand and estimated the maximum price payable for gas at each location, the next section evaluates the gas demand that can be captured at each imputed value.

Profile of gas demand

Time profile of gas demand

Putting together the several components of potential gas demand we get the following time profile.

Table 14.12 Demand of gas at various prices (MMCMD)

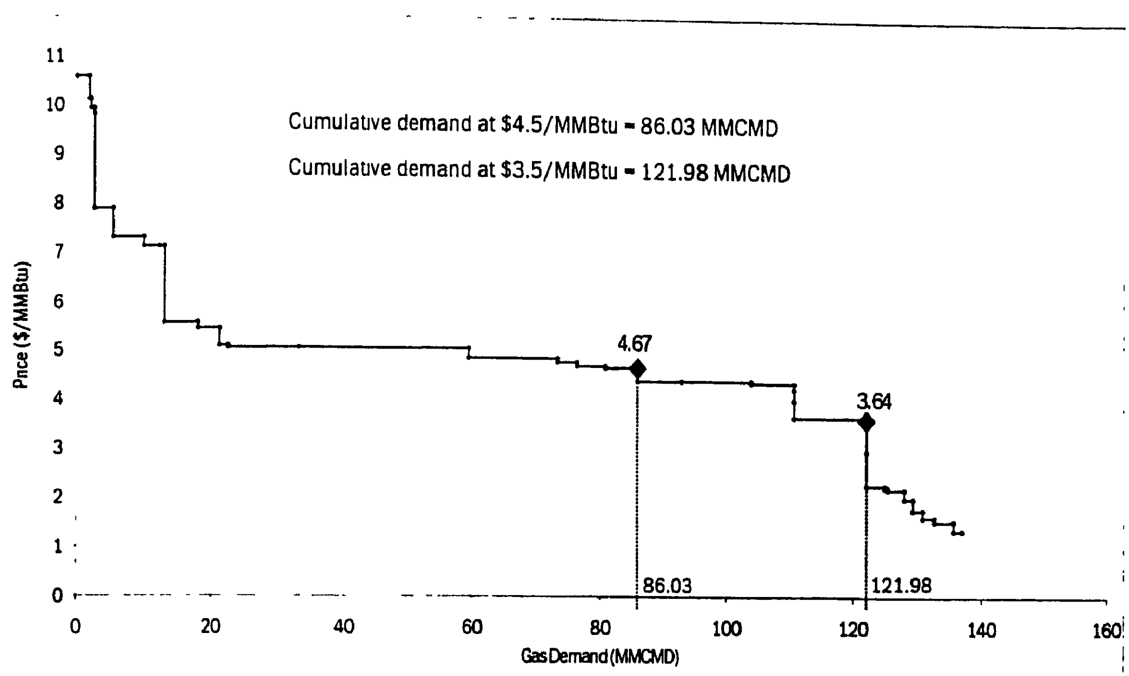
	Existing	2006/7
Demand at gas price \$3.50/MMBtu		
Power	46.33	68.75
Fertiliser	40.22	40.22
Industries	1.87	2.65
Captive	5.78	10.36
Total demand	**94.20**	**121.98**
Demand at gas price \$4.50/MMBtu		
Power	21.04	32.80
Fertiliser	40.22	40.22
Industries	1.87	2.65
Captive	5.78	10.36
Total demand	**68.91**	**86.03**

Price profile of gas demand

Imputed values of gas have been used along with the sectoral gas demand estimates to arrive at the price profiles of gas demand in 2006. All India price

profile for 2006 is shown in Figure 14.2. Details of India and regional price profiles are shown in Annexure 14.4.

Figure 14.2 All India price profile of gas demand in 2006



LNG import projects

In view of the problems faced in importing gas by pipelines, the LNG option has been pursued to meet immediate needs for imported gas. Proposals for constructing LNG terminals have been made by various consortia of Indian and multinational oil and gas companies and promoters of power plants. The LNG trade is undergoing a transformation as new suppliers emerge in West Asia. The downturn of LNG demand in South Korea and Japan has made India a key market for LNG.

The supply sources identified by promoters of LNG import proposals in India are listed in the Table below.

Table 14.13 Identified sources of supply to proposed LNG terminals in India

LNG terminal	Capacity (MMTPA)	Supply source	Remarks
Jamnagar	5.0	Iran	
Pipavav	3.0	Under identification	MoU signed earlier with Yemen voided
Dahej	5.0	Qatar	
Hazira	5.0	Shell group's sources	
Trombay	3.0	Total Elf Fina sources	Balance quantity yet to be sourced
Dabhol	5.0	Oman (1.7 MMTPA) Abu Dhabi (0.54 MMTPA)	

Kochi	2.5	Qatar	
Ennore	2.5	Qatar	
Kakinada	2.5	To be decided	Malaysia, a contender
Gopalpur	5.0	Australia	
Total	38.5		

The status of proposed LNG projects in India has been discussed in Annexure 14.5. The projects that are likely to go through by 2006 are listed in the Table below.

Table 14.14 Expected LNG imports

Year	Quantity	Cumulative	Cumulative	Location (MMTPA)
	MMTPA	*MMTPA*	*MMCMD*	
2004	4.5	4.5	18	Dahej (2.5), Dabhol (2)
2005	2.5	7	28	Dahej expansion
2006	2.5	9.5	38	Hazira (2.5)

Gas marketing strategy

As stated earlier, the objective of the marketing strategy is to maximise the netback to ONGC from selling gas. Gas demand from market segments having higher imputed values have to be targeted.

Though domestic gas price is now linked to international prices of fuel oil. The linkage is under review and full parity with fuel oil is expected in the near future. The gas price should get another boost in 2004 when LNG arrives at Gujarat. Thus, the gas price may pass through some intermediate stages before fully market driven prices are re-introduced.

A better fuel oil linkage

The current consumer price of gas at landfall points is linked to the price of a basket of fuel oils as shown in the table below:

Table 14.15 Natural Gas Pricing against a basket of Fuel Oils

Year	Percentage of LSHS/FO price	
	General Price	Concessional Price for the NE States
1997-98	55%	35%
1998-99	65%	40%
1999-2000	75%	45%

The price is determined and notified by GAIL with the approval for the Ministry for every quarter depending upon the average price of the following basket of fuel oils (with equal weights to each type) based on the figures obtained from Platt's Oilgram for the previous quarter.

- Cargoes FOB, Med Basis, Italy (1% Sulphur)

- Cargoes CIF NEW Basis, ARA (1% Sulphur)
- Singapore, FOB, HSFO 180 cst (3.9% Sulphur)
- Arabian Gulf, FOB, HSFO 180 cst (3.9% Sulphur)

The price varies between the floor of Rs 2150/MCM (thousand cu mtrs) and the ceiling of Rs 2850/MCM. The revision to full parity with fuel oil would not be effective unless the ceiling price is revised upward. At crude oil prices of $22-28/bbl, the gas price is expected to be $3.45-4.40/MMBtu or Rs 6296-8013/MCM (assuming 10,000kcals/cu.mtr.). In view of the estimated Long Range Marginal Cost of production of Rs 1800/MCM for ONGC (Sankar Committee,1997), it is unlikely that ONGC would be allowed by the government to charge such high prices. The government has allowed fuel oil linked prices in two other cases, Panna-Mukta-Tapti and Ravva. In the first case there is a ceiling price of $3.11/MMBtu and in the second case the ceiling price is $3/MMBtu. Accordingly, a ceiling for ONGC may be imposed somewhere between $2.5-3.0/MMBtu.

ONGC should try to negotiate a high ceiling price but it may be difficult to do so. In view of the recent experience with high oil prices, consumers would be sensitive to the ceiling. Besides, a high ceiling may give rise to the demand for a low floor price. It would be more feasible for ONGC to negotiate a better fuel oil basket. So long as the ceiling price is acceptable, the consumers may be less sensitive to a higher price within the ceiling. This could be done by choosing only low sulphur fuel oils, altering the weight in favour of low sulphur fuel oils in the basket and by changing fob prices to cif.

Pooled price for LNG

What would be the effect of LNG on the prices of domestic gas? Would domestic gas continue to be sold at fuel oil linked prices while LNG is imported and sold at higher prices? It is difficult to answer the question now as little is known on how imported LNG is going to be priced. So far as is known, the cif LNG prices at the Gujarat coast would be:

At $18/bbl JCC: $2.55-2.75/MMBtu
At $25/bbl JCC: $3.45-3.80/MMBtu

Adding 40 cents/MMBtu for regasification, the gas price ex-receiving terminal would come to $2.95-4.20/MMBtu. We may add 10 cents/MMBtu for locations in the southern and eastern coast for additional ocean freight.

If the gas is put into the HBJ pipeline, it would reach consumers in western and northern India with the addition of another $1/MMBtu as the

transportation cost. The price to HBJ consumers would rise from $3.95-$5.20/MMBtu as the crude oil price goes from $18/bbl to $25/bbl.

It should be noted that Petronet LNG has not yet tied up any customer. Apparently the problem is that the LNG price is open ended, without a cap. According to press reports, one suggestion to solve the problem is to pool the prices of domestic gas and LNG imported by Petronet. The domestic gas price is already a pooled price with customers paying the same price for ONGC gas and costlier gas from private fields. The proportion of costly gas would increase if LNG is also pooled in. One way of pooling would be to mix 20 MMCMD of LNG with 60 MMCMD of gas now available (not counting the north-east). The imputed values computed for important customers along HBJ are reproduced below: ($/MMBtu)

Fertiliser expansion - 4.24
Fertiliser conversion -4.85
Fertiliser existing - 5.05
NTPC Anta - 4.36
NTPC Auraiya -4.40
NTPC Gandhar - 4.93
NTPC Kawas - 5.03

This shows that the expected netback price at Dahej would be at least $3.25/MMBtu. As we have seen earlier, regasified LNG would cost $3.45/MMBtu at a JCC price of $25/bbl. If this has to be sold at $3.25/MMBtu, the domestic gas price has to be capped at $3.2/MMBtu. This does not pose a problem. However, if LNG has to be covered at a JCC price of $30/bbl, the domestic cap would be $2.9/MMBtu. If the expected netback is lower, the cap will be lower. If the proportion of domestic gas is taken to be lower to cover decreasing production, the cap would be lower still. **The implication for ONGC is that if pooling is unavoidable, ONGC must be fully involved in the price fixing exercise.**

NELP gas

As seen above, pooling would lock the price of the bulk of ONGC gas into fuel oil linkage. However, ONGC would be free to get a better price for gas from NELP blocks. Private gas producers would be similarly placed. When LNG becomes available, the price of this gas could be raised to import parity. However, most of this gas is expected to be found around Gujarat or Andhra Pradesh where gas-to-gas competition may keep the price down. In view of the possibility of

increasing the gas price, it would be prudent not to sell this gas on long term contracts. At least, the price should be kept flexible.

Individual vs bulk sales

Price negotiations with consumers would require the building up of special teams and there would be a cost attached to it. ONGC may avoid a part of this cost by selling gas in bulk to GAIL or other such agencies who would undertake the tasks of transport and marketing. This would be a good choice if a number of agencies were available to do this job. In such a case, the agency could be selected through competitive bidding and the netback to ONGC could be maximised. For quite some time, GAIL may be the only marketer but there is a chance that British Gas or the oil marketing company could enter the market and make it competitive. Bulk selling may be more feasible in cases where the marketing risk appears to be large. These decisions could be taken on the merits of the particular case.

The price for bulk sales would be fuel oil linked. As in the case of gas sold through GAIL, the choice of fuel oils would be important, as would be the price ceiling or the linkage. These could vary between regions depending on the customer profile. ONGC would need to have a clear idea of the purchasing power of the customers even while negotiating bulk sales.

Bulk prices will be linked to fuel oil. What basket is chosen will be decided by bargaining. ONGC has to settle depending on their on assessment of what the market will bear. GAIL will earn a return on pipelines and the margin. No commission has to be paid by ONGC.

Transmission of gas is going to be a regulated business. Normally, this would not be attractive compared to the upstream sector and it may be necessary for ONGC to transport gas only in specific cases where a transporter is not available or the available transporter is inefficient, which means the netback to ONGC would suffer. In such cases, regulation may require ONGC to separate the accounts for selling and transportation. ONGC may also have to provide access to the pipeline to other parties.

Coping with variable prices

The work of development or additional development in a gas field would be undertaken only when the incremental cost is compensated by the incremental income. The long term gas production profile of ONGC shows that gas production in some areas will increase up to 2006/7. Any additional investment required for increasing the flow of gas is to be justified by the expected revenues.

So far as these fields are concerned, it is expected that all the producible gas has to be sold to GAIL at prices fixed by the government. As we have seen, the price of this gas is likely to reach fuel oil parity. What is the expected fuel oil price over the economic life of the investment? The answer to this question depends on the assumptions as to the long term behaviour of crude oil prices. The various price forecasts available for 2020 are:

Energy Information Administration : $22/bbl.

International Energy Agency : $30/bbl.

European Commission : $ 28/bbl.

These forecasts should be compared to the OPEC announcement that the price of the OPEC basket will be kept within a band of $22-28/bbl. As an oil and gas producer, ONGC cannot be guided by these forecasts in evaluating development proposals. Shell takes the benchmark price of $14/bbl so that all projects of Shell remain profitable even when the oil price drops to that level. ONGC has to work out a suitable benchmark price depending on their perception of risks.

Where ONGC is free to price the gas, the uncertainties linked with a variable gas price could be avoided by selling the gas at a steady price. This would be welcome by Indian gas consumers as many of them are in the public sector and are, therefore, averse to taking risks. Hardly any gas seller would, however, agree to a steady price which eliminates the possibility of large gains. A compromise acceptable to both the buyer and the seller would be a variable price subject to a floor and a ceiling. Generally, the ceiling would be dictated by the cost of alternative fuels to the buyer whereas the floor would be a function of the production cost.

Contract conditions

Gas consumers in India may have difficulties in signing long term contracts with stiff take-or-pay provisions. Gas suppliers who depend on project finance for developing their fields may find such terms unavoidable. ONGC could have an advantage here, over other suppliers. If the market is competitive, ONGC could offer more flexible contract conditions if that leads to a higher market share. In some cases, a similar advantage could be derived by offering Rupee prices in stead of Dollar denominated prices.

The pricing and other conditions would have to be innovative if gas is to be sold to industrial consumers. Most of these may be able to afford only intermittent supplies, depending on movements in coal and fuel oil prices. A two-part transportation tariff in which fallback suppliers do not pay capacity charges could help in developing such customers. It would be in the interest of ONGC to influence regulatory policy in this regard.

PART-3
Value Added Products

15 LPG Marketing

Introduction

LPG sales have recorded an average growth of 10.6% over the last decade. While earlier demand far exceeded supply, of late, with the commissioning of new refineries, supply constraints have been relaxed considerably. In fact, recent trends reflect saturation in domestic LPG sales. Registered waiting lists of oil marketing companies have been liquidated and additional LPG demand would primarily emerge from rural and semi-urban areas. Overall, the demand for LPG is expected to grow at an annual rate of 8% over the Tenth Plan period.

LPG availability from domestic sources, i.e., refineries and fractionators, however, would be well below expected demand, necessitating imports. LPG demand-supply outlook is summarised in Table 15.1. (Detailed description of the Indian LPG market is presented in Annexure 15.1).

Table 15.1 LPG demand-supply outlook (TMT)

Year	Demand	Supply	Deficit
2001/02	8055	6428	1627
2002/03	8776	6328	2448
2003/04	9528	6766	2762
2004/05	10310	6903	3407
2005/06	11123	7766	3357
2006/07	11966	9348	2618

While overall imports are necessitated, there would be regional imbalances wherein, the western region has surplus availability of LPG while other regions are in deficit (See Table 15.2). The Western LPG market is covered in greater detail in Annexure 15.2.

Table 15.2 Projected demand-supply balance in the western region (TMT)

Year	Demand	Supply	Surplus
2001/02	2142	4394	2252
2002/03	2334	4302	1968
2003/04	2534	4734	2200
2004/05	2742	4882	2140
2005/06	2958	4845	1887
2006/07	3182	6076	2894

Options for ONGC

The western surplus has a significant bearing on the marketing options for ONGC. ONGC's fractionators, located in the West, contribute to this surplus. Excess production in the west, would have to be moved to other regions. LPG production from ONGC's fractionators (Table 15.3), accounts for about 27% of the total LPG availability in the West.

Table 15.3 LPG production profile from ONGC's fractionators (TMT)

Fractionator	2002/03	2003/04	2004/05	2005/06	2006/07
Uran	408	419	397	371	352
Hazira	546	527	488	488	488
Ankaleshwar	10	9	8	7	6
Gandhar	49	47	43	33	27
Total	1013	1002	936	899	873

Output from ONGC's fractionators is, however, expected to decline in the future. Any strategy adopted must be cognizant of this fact. The alternatives available to ONGC are:

- Direct marketing of LPG by ONGC
- Exports
- Sales to parallel marketers
- Renegotiate sales of LPG to oil marketing companies (OMCs) on commercial terms

Direct Marketing

Bulk versus bottled sales

LPG is primarily marketed either in the form of bulk sales to industrial/commercial users or retail sales in the form of bottled LPG. As a marketing option, bulk sales score over retail as they entail substantially lower investments as compared to retail which requires investments in bottling pants, dealerships, distribution, etc. The demand for bulk sales for LPG in the country, however, is fairly limited. LPG requirements by the total industrial/commercial sectors add up to 638 TMT only. In contrast, ONGC's current LPG production aggregates 1,214 TMT. Thus, even if ONGC were to capture the entire industrial/commercial market in the country, the total offtake would account for only half of its production, necessitating retail sales of the remaining.

A more realistic scenario indicates even lower possibilities for bulk sales by ONGC. There is a spatial dimension to the bulk LPG market, which cannot be ignored. With ONGC's production facilities located in the western part of the

country, it is unlikely that it would be a competitive supplier throughout the country as freight costs are substantial. ONGC's target markets are also, thus, likely to be limited to the western region only. The western region, however, accounts for only a fifth[a] of the total bulk LPG market in the country. The effective bulk LPG demand for ONGC is thus likely to be only 120 TMT, representing only 10% of the LPG production by ONGC. The remaining would have to be marketed in bottled form.

Economics of bottling

It is inevitable, hence, that in case ONGC chooses to engage into direct marketing of LPG, it would have to opt for retail marketing. Bottled LPG from ONGC would have to be competitive with sales from established players in the industry – IOC, BPC and HPC. The price of bottled LPG offered by ONGC , thus, would have to be at least at par with that offered by other OMCs. It may be noted that setting up of a bottling plant entails substantial investments. While other OMCs have already recovered their investments in LPG marketing infrastructure by and large, ONGC would have to recover its investments from prices dictated by the OMCs.

At present, LPG prices are controlled by the Government through the APM (Administered Pricing Mechanism). Under the APM, OMCs charge Rs 970/MT towards filling (bottling) expenses. The APM, however, is scheduled to be dismantled by April 2002, the intended date for full deregulation of the oil industry. Since OMCs are already operating profitably at current price levels, it may be expected that a similar charge would be retained in the post-deregulation as well. On the upside, filling charges may be expected to be at most at Rs 1,346/MT as estimated by the Expert Technical Group (ETG).

These, however, turn out to be substantially lower than the costs of constructing and operating new bottling plants. Capital costs for a bottling plant vary depending on the degree of complexity in the plant, extent of automation, carousal size – 12/24 stations, volumes to be handled, etc. For instance, while IOC's 78 TMT plant at Shimoga in Karnataka entailed a total investment of Rs 60 crores, BPC's Loni plant in Uttar Pradesh also had similar order of investment, Rs 55 crores, although the plants capacity was only 44 TMT.

Typically, however, investments for a bottling plant of 44 TMT could be pegged at Rs 30 crores. Inclusive of operating costs, filling charges for such an investment are expected to be about Rs 2,091/MT (Annexure 15.3). It is evident

[a] Bulk PSU LPG sales in 1999/00 in the Western region of 100 TMT accounted for 19% of the total bulk LPG sales of 534 TMT

that if ONGC's filling charges are twice as much as those of other OMCs, it is unlikely that bottled LPG from ONGC would be competitive to that from other OMCs. Even if OMCs hike filling charges to those levels as estimated by the ETG, filling costs for ONGC would be about 55% more than those for other OMCs.

In summary, if ONGC chooses to engage into direct marketing of its LPG, it would have to:

- Take established OMCs head-on to carve a market share for itself
- Invest in bottling infrastructure as scope for bulk marketing is fairly limited
- Match its prices, for both bulk and bottled LPG, to those of other OMCs

In doing so, it is likely that ONGC would be out priced by its competitors. In addition, direct marketing would require ONGC to commit itself to brand building. Marketing/brand building expenses can be substantial and it would not be prudent for a company to invest in brand building for a product, the production of which is expected to decline in the future.

Another opportunity that has arisen for direct marketers is the use of LPG in automobiles. Government of India has recently notified the use of LPG as an automotive fuel and several marketing companies are bracing to get a head start. However, the exploitation of this opportunity by ONGC is somewhat constrained due to high initial investment required in the project. And given the fact that ONGC's production is concentrated at few locations, it would require big investment in infrastructure to have a noticeable presence and a critical mass, something that may not be prudent for a declining production. It is estimated that on the average a stand-alone LPG station costs up to Rs. 35 lakhs. This would go up if the fuel station is to give consumer the choice of all automotive fuels. In fact, OMCs are planning to give consumers the range of automotive fuels at one location. This would mean that the costs for OMCs will be largely incremental and hence will be less than those required by ONGC if it has to start from the scratch. This will give OMCs a cost advantage with respect to ONGC. And given the fact that several such stations may be required to achieve a critical mass, the whole project can be quite costly. All these issues do not point towards Auto LPG being an attractive option for ONGC.

Exports

With domestic LPG demand exceeding supply, large-scale exports have never really been an option as far as LPG is concerned. In 1999/00, while 1.4 MMT of LPG was imported, exports aggregated 31 TMT only. The limited exports undertaken are primarily those by IOC to Nepal.

The preceding analysis highlights the fact that LPG is likely to be in deficit over the Tenth Plan period as well, necessitating large scale LPG imports. In such a scenario, exports do not appear to be an attractive option, particularly given the low realisations from exports as against to domestic prices at import parity. Table 15.4 presents the indicative import parity price for LPG on the Indian west coast in line with Saudi Aramco's postings for Butane/Propane for December 2001. The same is contrasted against likely export realisations benchmarked against Japanese cif prices for Butane/Propane in December 2001 in Table 15.5.

Table 15.4 Indicative import parity price for LPG: December 2001

Parameter	Units	Value
Fob: Mid East Gulf	$/MT	210
Load port charges	$/MT	1
Freight	$/MT	35
C&F	Rs/MT	11808
Insurance @ 0.3%	Rs/MT	35
Ocean Loss @ 0.3%	Rs/MT	35
Cif	Rs/MT	11879
Landing charges @ 1%	Rs/MT	119
Cif + Landing charges	Rs/MT	11998
Customs Duty @ 10%	Rs/MT	1200
LC Charges @ 0.3%	Rs/MT	36
Port dues	Rs/MT	100
Import Parity Price	Rs/MT	13333

Table 15.5 Likely export realisations: December 2001

Parameter	Units	Value
Japanese Cif	$/MT	225
Less:Freight	$/MT	35
Less:Ocean Loss, insurance, etc	$/MT	11
Fob	$/MT	179
Fob	Rs/MT	8573
Less: Port dues	Rs/MT	100
Export realisation	Rs/MT	8473

As is evident form the above, export realisations are likely to be substantially lower (about Rs 5,000/MT). In addition, ONGC would have to invest in new infrastructure to export LPG - a dedicated pipeline to the port, storage facilities at the port, loading arrangements, cryogenic facilities for transportation, etc. The costs incurred in development of such facilities would have to be borne out of the export earnings. The net realisation from exports is, thus, likely to further reduced.

The declining production of LPG again becomes a critical issue while considering the viability of exports. A buyer, in general, would tend to lock on to a secure supply source, i.e., where availability is not an issue. In case of exports

by ONGC, the company would have to look for buyers who are willing to contract reducing volumes.

In summary, LPG exports do not appear to be a lucrative option as,

- There are likely to be few buyers willing to contract for reducing volumes
- Export realisations would be much lower than domestic prices (likely to be at import parity)
- Investments would be required to facilitate exports

Sales to parallel marketers

The possibilities of sales to parallel marketers are also bleak. The parallel market trade is fairly limited, with total imports by parallel marketers aggregating only 178 TMT in 2000/01. The trade in the western region is further limited and distributed amongst a number of players - Bharat-Shell, SHV, Hindustan-Domestic Oil & Gas Co Ltd., and Reliance.

The key reason for limited operations by parallel marketers has been their cost disadvantage against public sector (PSU) OMCs. Parallel marketers have had to compete with PSU sales, subsidised by the Government through the oil pool account. As a result, over the years parallel marketers have suffered substantial losses and are now threatening to pull out[a] of the business, unless the subsidies are extended to their operations as well. Companies like Bharat Shell have put a freeze on further investments in India and have decided to divert funds earmarked for Indian markets to other destinations like China.

The ensuing scenario precludes any possibilities of marketing tie-ups with parallel marketers.

Commercial agreements with OMCs

Reviewing the options available to ONGC, it appears that direct marketing and exports are not likely to be lucrative strategies for the company. Given the market scenario, wherein retail bottled LPG sales constitute the bulk of the market, ONGC's dependence on OMC's for assured offtake of its production seems inevitable. With 6,000 plus distributors across the country amongst the OMCs, they have an established delivery chain to reach out to consumers. In contrast, the ONGC, till date, has solely been a producer only, isolated from the markets and consumers. With ONGC's core competence in production, it would

[a] "LPG MNCs threaten to exit, seek subsidies". Business Standard, 18th August 2001

be prudent for ONGC to synergise its operations with OMC's, rather than competing with them for a share in the retail business.

The prevailing mechanism

Current marketing arrangements for LPG produced by ONGC are also via the retail networks of OMCs. There are dedicated pipeline links from ONGC's production sites to bottling plants of OMCs:

- Uran: Pipelines to BPC's bottling plants and the BPC/HPC refineries
- Hazira: Pipeline to IOC's bottling plant
- Ankleshwar: Pipeline to HPC's bottling plant

At Gandhar, while there is no dedicated pipeline for evacuation, IOC's neighbouring bottling plant is fed through tanker trucks. The bottling capacities of OMCs at these sites, however, aggregates to 288 TMT only (Table 15.6).

Table 15.6 Bottling capacities of OMCs at ONGC's production sites (TMT)

Site	OMC	Bottling Capacity
Uran	BPC	132
Hazira	IOC	44
Ankaleshwar	HPC	44
Gandhar	IOC	68
Total		**288**

The remaining is distributed by OMCs across their bottling plants in Western and Northern India in line with the monthly supply plan prepared by the Oil Co-ordination Committee (OCC).

The OCC also works out the price applicable for sales to OMCs. LPG prices continue to be administered through the oil pool account. Each month, the OCC works out the fractionator gate price for LPG produced from all fractionators (and refineries as well). The oil marketing companies pick up the same from refineries and fractionators at the Tariff Adjusted Import Parity Prices (TAIPP), also worked out by the OCC. The difference between the fractionator gate prices and the TAIPP is surrendered or claimed, as the case may be. **It may be noted that, as of now, there are no legally binding commercial agreements behind these exchanges.**

Post-deregulation scenario

Full deregulation of the oil sector is expected by April 2002. Post-deregulation, while the APM would be dismantled, the Government has decided to continue reduced subsidies on LPG and Kerosene. These would be brought out of the

ambit of the oil pool account and transferred to the fiscal budget. The system of fixing the TAIPP for controlled products is, thus, likely to be discontinued and refineries/fractionators would sell their products to OMCs on commercial terms.

Post deregulation, product pricing would be governed by market forces. There would be no Government control on prices and OMCs would be free to charge appropriate prices. Since LPG is likely to remain in deficit, a scenario wherein domestic requirements would be met with imports at the margin, market prices for LPG, would in general, reflect product prices in international markets, i.e., import parity. As marketing companies, OMCs would try to procure LPG from producers at the lowest possible prices. However, ONGC as a producer should aim to receive prices as close to as possible to the import parity prices for LPG. Current fractionator gate prices received by ONGC, in fact, are far lower than the actual import parity prices (Table 15.7).

Table 15.7 Current realisation from LPG sales vs. import parity prices: Apr'2001 - Oct'2001 (Rs/MT)

Month	Fractionator Gate Price*	Import Parity Price#	Difference
Apr	12463	18838	-34%
May	9416	15879	-41%
Jun	8374	15610	-46%
Jul	9303	15879	-41%
Aug	9523	15476	-38%
Sep	8077	14265	-43%
Oct	7263	13996	-48%

* Data furnished by ONGC
# As per price build up indicated in Table 15.10

On an average, the current price realised by ONGC on LPG sales is about 40% lower than the prevailing import parity price.

Recommended strategy for ONGC

Post-deregulation, ONGC should, thus, aim,

a) To convert current marketing arrangements into legally binding commercial agreements
b) To seek ***near import parity*** prices for LPG sold to OMCs

ONGC may seek take or pay agreements or a cut in marketing margins from OMCs, but it is likely to be on a weak wicket to do so. It must target near import parity prices, i.e., sales at a slight discount to the import parity price. The reasoning for the above is elaborated below.

Take or pay

ONGC could also explore the possibilities of entering into take or pay agreements with OMCs. Under such a system ONGC would be committed to provide specified volumes, while OMC would be committed to uplift the same. Failure by OMCs to do so would attract financial penalties.

It may be noted, however, that the ONGC is likely to be on a lean wicket as far as negotiating take or pay clauses is concerned. ONGC would be able to enforce take or pay obligations only if OMCs lack alternative supply options. A review of the demand in the western region indicates that the OMCs could, more or less, meet their requirements without access to LPG from fractionators (Table 15.8).

Table 15.8 Fall back arrangements for LPG supplies by OMCs

Supply Source	Availability	Bottling Plants	Capacity
RPL	1901	Rajkot	44
		Bhavnagar	44
		North (Jamnagar-Loni Pipeline)	1700
		Sub-Total	**1788**
		Surplus	**113**
Koyali	313	Ankaleshwar	44
		Hazira	44
		Gandhar	68
		Ahmedabad	66
		Gandhinagar	26
		Hariyala	34
		Sub-Total	**282**
		Surplus	**31**
HPC/BPC Refineries	497	Uran	132
		Mumbai	122
		Usar	109
		Jalgaon	44
		Aurangabad	44
		Chandrapur	44
		Khapri	44
		Chakan	44
		Pune	22
		Manmad	34
		Akola	44
		Sub-Total	**683**
		Surplus	**-186**
Ratnagiri (Imports)	200	Miraj	44
		Solapur	44
		Satara	22
		Sub-Total	**110**
		Surplus	**90**

RPL's production can be used for the Rajkot and Bhavnagar markets in Gujarat, while the rest can be pumped into the Jamnagar-Loni pipeline for northern markets. The remaining markets in Gujarat can be easily fed from the Koyali refinery. Likewise, the markets in Maharashtra can be fed from the Mumbai refineries, though some deficit remains. However, the import facility at Ratnagiri could be employed to bridge some of this gap and meet the demand in Southern Maharashtra. As far as additional demand in northern markets is concerned, imports up to 600 TMT could be facilitated at Kandla.

On the other hand, if OMCs fail to lift supplies from ONGC, ONGC could have a containment problem at hand. Since storage capacities at production sites exceed daily production levels, ONGC would be able to tide over short-run upliftment embargoes. The maximum cover, 7 days, is available at Hazira where storage capacity aggregates 22,500 cubic meters as against a daily production of 3,000 cubic meters of LPG. Beyond this, however, if OMCs fail to lift LPG, ONGC may have to shutdown its production. This would also hamper production of other value-added products like naphtha and Kersoene.

Sharing of margins

Under the APM, OMC's enjoy a marketing margin of Rs 922/MT on domestic LPG sales. As in the case of fractionator/refinery gate prices, the marketing margin too is fixed by the OCC. Margins are higher for sales to industrial / commercial consumers as prices for them are not administered.

Again, while ONGC may wish to get a share of the marketing margin, it is likely to be on a weak bargaining chip to do so. As discussed above, the OMCs do have fall-back arrangements for alternative supplies. As it is, the western region is surplus with LPG, and the OMCs have to evacuate this surplus, including ONGC's output, to the northern markets. Under the emergent scenario, it may not be possible for ONGC to press for a cut in marketing margins of OMCs.

Pricing: Discounts to import parity

It is apparent form the above, that continuing current marketing arrangements with OMCs would be the best option for ONGC. The OMCs, however, do have fall back options to bring in imports at the margin. Considering the import parity price for LPG, for the first seven months of the current fiscal, at Rs 15,706/MT (Table 15.7), the landed cost[a] of imported LPG at a northern market

[a] Import parity price at Kandla, plus pipeline freight from Kandla to Delhi via the Kandla/Jamnagar-Loni pipeline. Freight considered is that as recommended by the Expert Technical Group for new pipelines, i.e., Rs 1.13/MT/Km

for OMCs, say, the bottling plant at Madanpur Khader (Delhi) is estimated at Rs 17,098/MT.

Current railway freight[a] for moving the same from Hazira, on the other hand is Rs 1,147/MT. Thus, if ONGC offers LPG for Delhi from Hazira at Rs 15,952/MT (Rs 17,098/MT less Rs 1,147/MT), OMCs may well resort to imports and curtail upliftment from ONGC. Likewise, rail freight from Uran[b] to Delhi is Rs 1,621/MT. OMCs would not be keen to pick up LPG from Uran for ex-Uran prices higher than Rs 15,478/MT (Rs 17,098/MT less Rs 1,621/MT).

If, on the other hand, ONGC were to offer the LPG at a slight discount to the import parity price, LPG from its fractionators would be readily sought by OMCs.

For instance, if ONGC offers LPG at a 5% discount (say) to the import parity price, the contract price for OMCs would be lower by Rs 855/MT as against that in the case of LPG imports. On an annualised basis, this discount would affect savings in procurement in excess of Rs 100 crores.

For ONGC, even with the 5% discount that assures full evacuation of its output, realisations would be substantially higher than what it receives today. As against the average import parity price of Rs 15,706/MT, the average fractionator gate price set by the OCC for the same period was Rs 9,203/MT (Table 15.7). Even if ONGC offers LPG at a 5% discount to the import parity price, its realisation would be higher by Rs 5,895/MT at Hazira and Rs 5,420/MT at Uran. On an annualised basis, the net gain for ONGC would be about Rs 650 crores (Rs 360 crores at Hazira and Rs 290 crores at Uran).

Concluding remarks

While deregulation of the oil industry per se provides opportunities for ONGC, the options available to ONGC do not appear to be lucrative. Direct marketing of LPG would pit ONGC against established oil marketing companies. Under the resultant scenario, ONGC would have to necessarily invest in bottling infrastructure. Such investments, are likely to render ONGC uncompetitive to established players in the industry.

Exports too turn out to be unattractive, with realisations far below those in the domestic market which are likely to be at import parity. Again, exports would require investments in evacuation and port infrastructure, which further reduce net realisations from exports. Sales to parallel marketers are also ruled

[a] Rail distance from Hazira to Delhi is 869 kms. The applicable railway freight for a train load of LPG (general classification 220) for the distance slab 876 - 900 kms is Rs 114.64 per quintal

[b] Full rail loading facilities available at BPC's bottling plant at Uran

out given their limited market share. Additionally, possibilities of parallel marketers winding up their operations is not precluded, given their precarious financial position.

Given the market scenario, it is recommended that ONGC should opt for continuing current marketing arrangements with OMCs. However, post deregulation, these arrangements should be backed by commercial agreements, clearly specifying delivery points, volumes, prices, credit terms, etc.

There is a huge difference between the current price realised by ONGC and the prevailing import parity prices for LPG. ONGC should aggressively negotiate to hike its realisation to near import parity levels. Slight discounts by ONGC vis-à-vis the import parity price would assure 100% offtake of its production by OMCs. Even with discounts to import parity prices, the net gain for ONGC would be substantial, enhancing its profitability considerably.

16 Marketing strategy for naphtha

Introduction

Naphtha, a light distillate, is used in power generation, urea production and petrochemical plants for different purposes. In power generation, it is used as a fuel; in urea production, it is used primarily as a feedstock to produce ammonia but is used as a fuel also and in petrochemical plant, it is used to extract other chemicals like benzene etc. Gas can replace naphtha in power generation and fertiliser production. Thus, apart from refineries, ONGC's naphtha faces competition from domestic gas and LNG. It is a deregulated commodity and can be sold freely domestically or can be exported. The naphtha market characteristics have been detailed in Annexure 16.1.

Though there are net imports of naphtha in the country, as shown in table 16.1, the figures disguise the fact that most of these imports are of petrochemical grade naphtha which is not comparable with naphtha produced in the country.

Table 16.1 Naphtha imports and exports (TMT)

	1996/97	1997/98	1998/99	1999/00	2000/01
Imports	15	1874	2407	1917	3165
Public Sector			168	230	340
Pnvate Sector	15	1874	2239	1687	2825
Exports	2589	2048	720	583	2882
Net Imports	-2574	-174	1687	1334	283

Source. OCC

If we exclude all imports of naphtha on the basis that these are of petrochemical grade naphtha and hence are not comparable with ONGC's naphtha and simultaneously exclude the production from Reliance refinery at Jamnagar on the basis that its naphtha production is exported in a swap agreement, we have the following demand supply outlook for naphtha. The detailed demand supply outlook has been given in Annexure 16.2.

Table 16.2 Naphtha demand supply gap (TMT)

	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07
Demand	8009	8104	7756	7915	6552	5777
Supply	9355	9598	9453	10291	10273	10775
Surplus	1346	1494	1697	2376	3721	4998

As this table shows, there is a projected surplus of 4. 9 million tonnes in the year 2006/7.

As ONGC's production is concentrated in the West, the demand supply scenario emerging in the region will have an important bearing on the marketing options.

The following table shows the demand supply situation for the Western region, given in more details in Annexure-16.2.

Table 16.3 Regional Naphtha demand supply gap (TMT)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Western Region	487	431	616	897	1554	1462

This projected surplus in the western region has to be kept in mind while deciding on marketing strategy.

The projected production of ONGC in the western region is shown below.

Table 16.4 Projected ONGC's production (TMT)

Location	Product	2002-03	2003-04	2004-05	2005-06	2006-07
URAN	Naphtha/NGL	234	243	232	220	212
Hazira	ARN	1182	739	653	654	656
	Light Naphtha	0	244	244	244	244
Ankleshwar	NGL	9	8	7	6	5
Gandhar	Naphtha	31	29	27	21	17
TOTAL		1482	1290	1189	1171	1160

Source. ONGC

Thus, 80% of the western region surplus can be accounted for by ONGC's production. Given the fact that IOC have a strong market presence in the western region (Annexure –16.1), it will be difficult for ONGC to dispose off its production.

Current status

Hazira

From Hazira, majority of the product is being transferred to OMCs, primarily IOC and HPC, either through pipeline or through rail/road network. However,

since ONGC started facing some problems in naphtha offtake by OMCs, it decided to sell naphtha directly. Thus, ONGC is also selling the product directly to Reliance Petrochemicals, Essar Steel and Essar Power. But these are spot sales invited by ONGC as and when the naphtha storage tanks threaten to overflow.

Table 16.5 Naphtha sales by ONGC (TMT)

	1st week	2nd Week	3rd Week	4th Week	Total
IOCL	11543	2574	15414	0	29531
HPCL	13826	13091	8658	10741	46318
ESSAR POWER	0	0	0	0	0
RELIANCE	0	0	29963	0	29963
Total	25369	15666	54036	10741	105815

Source: ONGC. Note: Individual figures may not add to the total due to rounding off

The following table shows the average basic and assessable value of naphtha for the past three years. These values are decided for a particular payment cycle which varies from OMC to OMC.

Table 16.6 Assessable vs. Basic value (Rs/MT)

Period	1/4/01 - 15/10/01	3/5/00 - 31/3/01	1/4/99 - 31/3/00
Assessable value	12566.00	13402.17	9560.00
Basic value	11499.50	12010.00	8608.93
Margin	1066.5	1392.17	951.07

Source. ONGC

The basic value is the Refinery Transfer Price (RTP) fixed on import parity basis by the OMCs from time to time. This is the price at which the refineries transfer naphtha to the marketing company. The assessable value is the price at which the marketing company sells naphtha to the final consumer. The assessable value is a buildup on the RTP and includes, inter alia, marketing cost of Rs 300/MT, some percentage of marketing margin, and a price-balancing factor. The assessable value is exclusive of all the sales tax and the state surcharges and the freight to the final consumer. Thus effectively, the difference between the basic value and the assessable value is the overall marketing margin OMCs are earning on ONGCs naphtha. This margin is fluctuating over time because of the fact that the marketing margin included in the assessable value is a percentage on the basic value and secondly, the OMCs are selling naphtha to the fertiliser plants at low margins.

Due to this margin, if ONGC were to sell naphtha directly, it can aim to get a price better than the basic price it is getting from OMCs.

However, as the following table shows, it receives even less when it sells naphtha directly to the domestic consumers.

Table 16.7 Realisation from direct selling (Rs/MT)

Consumers	Price for the penod 3/5/00 - 31/3/01
Essar Power	11893.87
Essar Steel	10321.19
IDPC	9267.96

Source. ONGC

The low realisation is due to the fact that these are spot transactions and hence the leverage is with the buyers since ONGC has got no choice but to sell its naphtha.

Apart from direct marketing, ONGC is also exporting some naphtha, primarily to Japan but only through IOC. In the period May 2000 to February 2001, ONGC exported about 300 TMT tonnes of naphtha with average realisation of 9820 Rs/MT, which is even lower than the spot sales to domestic consumers.

However, the billing rate for naphtha as realised over this period was Rs 11995.60/MT which means that various expenses involved in exports like SBM charges, pipeline charges, and canalising commission reduced the net realisation from exports to Rs 9820/MT.

Uran

The situation is almost the same at Uran with ONGC forced to export its naphtha from the Pir Pau jetty due to unsatisfactory upliftment of naphtha by the OMCs. Naphtha from this location is exported through HPCL and is sold on spot basis, which is more or less a distress cargo in the international market and hence the realisation is low.

Gandhar

From Gandhar, ONGC is selling all the naphtha to BPCL which is further selling it to GPCL Dahej which is using it as fuel. The transfer is through road tankers.

Ankleshwar

Naphtha from Ankleshwar is sold through BPCL and the mode of transportation is again road tankers.

Options for ONGC

ONGC has got the following options for selling its naphtha-

1. Renegotiate with OMCs.
2. Sell naphtha directly to the customers.
3. Vertical diversification.
4. Bypassing naphtha production.
5. Export the product.

Each of this option has certain benefits and costs that are analysed below.

1. Renegotiate with OMCs

Renegotiations with OMCs can be done on two terms. Firstly, it can be for a share in the marketing margin earned by the OMCs on selling ONGC's naphtha. Secondly, it can be a long-term purchase contract with one or more OMCs for the minimum quantity that ONGC can produce in the long term.

The main benefit of renegotiating for a share in marketing margin is that this will result in higher than current price realisation for its naphtha without any concomitant increase in costs. On the other hand, this may increase the offtake uncertainty since OMCs will get more reluctant to sell ONGC's naphtha, especially in the view of surplus situation in the country.

The main benefit of entering into long-term purchase contract with OMCs is avoidance of extra administrative costs of selling naphtha directly. Moreover, there will be no offtake uncertainty in that event and would avoid sales on distress on low prices. However, this may not fetch ONGC the best price as given the irregular pattern in the upliftment by OMCs, it may be difficult for ONGC to induce the OMCs to enter into a take-or-pay contract unless there is some price incentive.

2. Selling naphtha directly

As ONGC's naphtha production is concentrated in the western region, it is reasonable to assume that it can sell directly to the consumers in this region only since carrying it further away would render the product uncompetitive with respect to naphtha production in that region.

The main benefit of selling directly under long term contracts is reduced uncertainty of offtake by OMCs and hence reduced distress sales.
On the other hand, it will raise the administrative costs for ONGC since it has to enter into contract with each and every consumer separately.

For the month of October 2001, ONGC Hazira sold around 76 TMT of naphtha to IOC and HPCL and around 30 TMT directly to Reliance Industries as shown in the table 16.5.

Sales to direct consumers like Reliance and Essar are more of a distress sale whenever IOC fails to uplift naphtha in adequate quantity and as the tables 16.6 & 16.7 show, the realisations from these sales has been lower than those from sales to OMCs. So technically speaking, ONGC is still dependent on OMCs for naphtha upliftment at best prices.

The following table shows the comparative quality of naphtha produced by ONGC and by IOC.

Table 16.8 Quality comparisons

Parameters	Unit	Values for ONGC	Values for IOC
Distillation FBP, Max	Deg C	161-175 (Max 180)	180
Aromatics Max	% Vol	10-12 (Max 15)	15
Olefins Max	% Vol	1	1.5
Density at 15 Deg C	Gm/ml	0.73 Max	0.66-0.75
Gross Calorific Value	Kcal/kg	11280 Min	10200

As this table shows, there is not much difference between the quality of naphtha produced by ONGC and IOC except the Gross Calorific Value, which is higher for ONGC's naphtha. But this is too important to tilt the scales in the favour of ONGC and allow it to carve a market for its naphtha.

It is also possible that long-term contracts, not nearing their maturity date, are currently in force between the OMCs and consumers in which case it would be difficult for ONGC to break the existing bonds.

Pricing issues

Impact of LNG

The impact of LNG would be more pronounced on the prices of naphtha because gas can replace naphtha in many applications, especially fertiliser production and power generation. Shell is planning a LNG terminal at Hazira and Petronet is building a LNG terminal at Dahej. Thus, within few years, there is a possibility of LNG flooding the Western sector. In such a case, the naphtha upliftment will fall and so will the prices.

Impact on Fertiliser sector

The consumption of gas by the fertiliser sector was 7.625 billion cubic metres in 1996-97 and is expected to reach 20 billion tonnes in 2001-02[a]. With the coming of LNG, almost all the fertiliser units are expected to shift to gas. This is due to some intrinsic benefits of using gas for urea production, as shown in the table below.

Table 16.9 Comparison among various feedstocks for producing urea

Feedstock	Investment (Rs, crores) Grassroot	Energy Consumption Gcal/T of urea	Feedstock Qty/T of urea	Feedstock Prices Rs/Unit	Rs/MMBtu	Rs/T of urea
Indigenous gas	1425	5.07	549 SM3	3936/1000 SM3	58.35	2161
LNG	1425	5.07	548 SM3	6666/1000 SM3	162.54	3385
Naphtha	1474	5.10	0.483/Te	8483/Te	187.60	4097
Fuel Oil	1976	6.57	0.663/Te	5911/Te	125.52	3921

Source. Fertiliser Pricing Policy, Department of fertiliser, March 1998, page 42

As this table shows, the cost of feedstock per tonne of urea produced is higher in the case of naphtha than using gas and LNG. Moreover, the capital cost of setting up the new urea plant is also lower for a plant using gas/LNG than for a naphtha-based plant. With the costs of conversion of an existing naphtha based unit into a gas-based unit being negligible, one expects that the fertiliser plants in the country will shift to gas. And this fact is amply illustrated in the demand supply scenario built in Annexure-16.2 that shows a huge drop in naphtha demand after coming of LNG.

The landed cost of LNG is still indexed to crude oil prices. But there is a possibility that this may become weaker as the LNG market further develops. However, if we calculate the landed cost of LNG according to the current estimates, at crude price of $18/bbl, the fob Middle East of LNG comes out to be 2.65$/MMBtu. This fob price increase by 0.15$/MMBtu for every 1$ increase in crude oil price. Adding to it the transportation from Middle East to West Coast India and the relevant duties and regassification costs, the ex-Hazira cost of LNG comes out to be 3.68$/MMBtu.

Imputed values methodology estimates that for naphtha price of Rs 7085/MT, the fertiliser plant will be indifferent between using naphtha and using gas landing at 3.68$/MMBtu. This price however varies for variations in crude oil prices as shown in the table below. The detailed calculations are at Annexure 16.3.

[a] Fertiliser Pricing Policy, Department of fertiliser, March 1998

Table 16.10 Imputed Values for naphtha versus LNG at Hazira

Crude oil price $/bbl	Landed cost of gas at the plant $/MMBtu	Imputed value of naphtha vs. LNG Rs/MT	Import panty pnces Rs/MT
18	3.68	7035	9260
22	4.33	8450	10960
25	4.82	9445	12235
28	5.31	10450	13510

The last column shows the average import parity prices, without any marketing cost charged by OMCs, at various crude oil prices at Hazira. The detailed buildup of the import parity prices is at table 16.11.

This table brings out that the imputed value for naphtha versus LNG is lower than the import parity price for naphtha. Thus, arrival of LNG will certainly reduce the naphtha realisation.

Impact on Power sector

During the past decade, government allowed Independent Power Producers (IPPs) to set up power plants based on liquid fuels like naphtha to limit the huge deficit in the power sector. This was also due to the fact that the plants based on naphtha or gas have a less gestation period. However, the state electricity boards were not in a position to pay for power generated from Naphtha, which due to its linkages with crude oil, proved to be too costly. Thus, many IPPs were shelved or were made on a dual fuel basis which means that they will shift to gas as soon as it is available. For example, Dabhol Power Company, which was using imported naphtha for its power plant, had the option to switch to gas when its LNG terminal is completed. Similarly, Essar Power is now mainly using gas and uses naphtha only as a swing fuel.

Thus, in the event of LNG coming to India, power generators will also shift to LNG.

Price war

One way to win away the existing customers of OMCs is to reduce the naphtha prices. But is this a feasible strategy in an oligopolistic market where the dominant player can undercut any price ONGC may set?

Recently, in response to the surplus situation in naphtha, the marketing committee of the OMCs changed the formula for setting the naphtha prices for fertiliser units that resulted in a reduction of prices by Rs 660 per tonne. Thus, in a collusive market, cutting prices is not an advisable strategy.

Cutting prices in a collusive market to undercut the market leader will result in a price war in which the company with longer staying power will survive. In this

context, both OMCs and ONGC are on equal footing since selling naphtha is not the main source of income for both and shutting down naphtha production is not an option for both. This would, however, result in revenue loss for both companies. Hence maintaining the current price structure is advantageous for ONGC.

Other possible pricing bases are energy equivalent pricing, calorific value equivalent pricing and yield equivalent pricing. Each of these pricing schemes price the product on the basis of its physical and quality characteristics and hence involve no element of price undercutting.

3. *Vertical diversification*

ONGC has got two options for vertical diversification. It can either acquire one of the two remaining PSU marketing companies or it can set up a downstream plant that uses naphtha as a raw material. Both these options are evaluated below with respect to naphtha upliftment.

Acquiring marketing PSU

The total all-India sales by BPCL and HPCL for the year 2000-01 were 1335.8 TMT and 1222.8 TMT[b] respectively. Sales in the western region over the same period for BPCL and HPCL were 708.1 TMT and 806.7 TMT respectively. BPCL sold 440.2 TMT less whereas HPCL sold 203.6 TMT more than its naphtha production in the domestic market for the year 2000-01. Comparing these with the ONGC's production of 1688.7 TMT last year, it becomes clear that none of the PSUs will be able to sell entire ONGC's production in the domestic market. However, this strategy may be beneficial at the different production centres individually. At Gandhar, ONGC sells entire quantity to BPCL which sells it to GPCL Dahej. Thus, at Gandhar, having BPCL within its fold may lead ONGC to internalising the marketing margins made on such sale. At Ankleshwar also, since the entire quantity goes to BPCL, this strategy may lead to higher price realisation.
Naphtha at Uran is exported via BPCL and hence having BPCL may internalise the canalising commission charged by BPCL on such exports.
The situation is not very different at Hazira because the naphtha produced at Hazira is primarily sold through HPCL and exports are undertaken directly by ONGC.

[b] Source: IPR, March 2001

However, the costs for acquisition will be high because of competition between various players, both Indian and international, for these two oil PSUs is likely to be very severe.

Setting up a downstream plant

Industries using naphtha are power/steel, fertilizers, petrochemicals or processors.
For ONGC, the main benefits of setting up a plant that consumes naphtha are –

1. No costs associated with sale of naphtha.
2. No reliance on either OMCs or private sector for naphtha offtake.
3. No competition from LNG.

However, this option should be evaluated in the light of the fact that ONGC's naphtha production is projected to decline by about 22% over the four-year period from 2002/3 to 2006/7. Assuming the same declining growth rate, the naphtha production will decline to 498 TMT by 2019/20. 1.1 million tonnes of naphtha can support a power plant of 1115 MW or a fertilizer plant of 2 MMTPA. But with declining production, it will need to purchase 602 TMT of naphtha from outside in order to sustain these capacities in the year 2019/20. This will bring, apart from fuel costs, additional costs in the form of administrative and marketing costs.

Moreover, this strategy involves a high initial capital investment with long pay back period.

Then ONGC will have to enter into multiplicity of contracts with various stakeholders, which will again increase the costs.
This strategy would, therefore over a long term, mean a complete diversification of business activities of ONGC, the suitability of which depends on various factors other than mere profits.

Setting up a processor plant is another option. Processors are the small crackers that extract ethylene, butadiene etc. from naphtha. However, unlike power and fertiliser plants, there is no assured offtake for products produced by processor plant. They would have to be sold in the open market and would entail marketing costs. This would again mean a complete diversification of the activities of ONGC.

4. Bypassing the production of naphtha

At Hazira, naphtha is produced at two points: at Kerosene Recovery Unit and again when LPG and ARN are separated. The production of naphtha can be bypassed only at Kerosene Recovery Unit, which means that ONGC has to

dispose off the NGL in addition to missing out on Superior Kerosene Oil (SKO) and Heavy Cut. While the whole economics of the process are difficult to work out given the limited scope of the study, it appears reasonable to conclude that this option would entail losses for ONGC apart from not solving the problem entirely.

5. *Export the product*

The benefits and costs of exporting naphtha can be estimated on the following grounds:

1. Projections for naphtha surplus

As shown in Annexure 16.2, naphtha is projected to be in surplus in all the regions of the country for the tenth plan period. This would make the task of finding buyers for naphtha very difficult. If ONGC were to export major part of its naphtha production, it need not rely on domestic offtake.

2. Reduction in domestic prices

Currently, naphtha is priced on import parity principle. But as naphtha becomes surplus in the country, prices may be set on export parity rather than import parity basis. As the tables below show, the export parity prices are lower than those based on import parity principle at various crude prices if sales are undertaken by OMCs.

Table 16.11 Import parity prices at Hazira

AG crude price	$/bbl	22	25	28
Naphtha price*	$/bbl	24	27	30
	$/MT	223	250	278
Premium	$/MT	5	5	5
Freight	$/MT	5.5	5.5	5.5
Naphtha c&f	**Rs/MT**	**10738**	**12002**	**13265**
Ocean Loss (at 0.3%)	Rs/MT	32	36	40
Insurance (at 0.3%)	Rs/MT	32	36	40
LC Charges (at 0.3%)	Rs/MT	32	36	40
Port Charges	Rs/MT	125	125	125
Landed cost of naphtha at Hazira	**Rs/MT**	**10960**	**12235**	**13510**

* Naphtha prices have been regressed from FOB AG prices. Details are at Annexure 16.4.

Table 16.12 Export parity prices at Hazira

Elements	Unit			
AG FOB	$/bbl	22	25	28
C&F Japan*	$/MT	226	259	292
Less freight from West Coast India to Japan	$/MT	17	17	17
FOB India	$/MT	209	242	275
	Rs/MT	9613	11126	12640
Expenses				
SBM Charges	Rs/MT	500	500	500
Wharfage	Rs/MT	90	90	90
Pipeline charges	Rs/MT	24	24	24
Price realised at Hazira	Rs/MT	8999	10512	12026

*The C&F Japan prices have been regressed from the AG FOB prices. Details are at Annexure 16.5.

The expenses included in the above table are given by ONGC and it is assumed that any other company will also have to incur these expenses while exporting naphtha.

3. Strategic location of production facilities

About 80% of total ONGC naphtha production is based at Hazira. This is a coastal location and hence would realise the maximum by exporting the naphtha than the inland refineries which have to incur the cost of moving the naphtha from their refinery to the port.

4. No competition from OMCs

It will be very difficult for ONGC to compete with the OMCs due to that fact that they have an established marketing set up, backed up by huge volumes and have marketing contracts with major consumers. On the other hand, ONGC has a relatively small production, concentrated at one location and is projected to decline over time.

If ONGC exports its naphtha, it would be avoiding the competition from the OMCs.

5. Diseconomies in selling naphtha outside the western region

The OMCs have a presence in all the regions and hence can sell naphtha at a cheaper rate in the respective regions. On the other hand, ONGC's naphtha is concentrated at one location and moving it across to some other region will involve huge freights that will render ONGC's naphtha uncompetitive. However, there are two major drawbacks in relying on exports.

1. Excessive fluctuations in international naphtha prices

Naphtha prices in the international market are very volatile and complete reliance on exports will lead to excessive fluctuation in the earnings. This is undesirable for any organisation.

2. Declining production of naphtha

International buyers are more likely to enter into long-term contracts with suppliers who can assure them of supply security. ONGC's naphtha production is expected to decline in the coming decade and hence it would be difficult for it to enter into long term purchase contracts with international buyers.

Export market for ONGC

Examining the global market logistically, we find that ONGC can sell its naphtha in the Asia-Pacific region as carrying it to region farther away would render the naphtha costly and hence uncompetitive. We would therefore restrict the analysis of the global situation in naphtha demand and supply to the Asia-Pacific region.

The following table gives the country wise import demand for naphtha in the Asia-Pacific region.

Table 16.13 Country wise import demand (TMT)

Country	2001	2002	2005	2008
Australia	-	-	-	-
Brunei	-	-	-	-
China	79	475	1,305	5,655
Indonesia	633	554		
Japan	20,484	22,303	25,190	25,309
Malaysia	870	791	593	514
Philippines	-	-	-	-
Singapore	1,661	1,780	1,780	1,780
South Korea	12,654	12,971	13,050	13,168
Taiwan	1,898	1,582	2,254	2,294
Thailand	554	475	316	198
Other Asia	554	554	554	554
Total	39,386	41,483	45,041	49,470

Source. FACTS-EWCI

As this table shows, there is an import demand for around 49 million tonnes from the countries in the Asia-Pacific region. The bulk of the demand comes from Japan followed by South Korea. China is another market that will import increasing quantities of naphtha in the coming decade followed by Taiwan. Even Singapore has the demand that can absorb ONGC's production.

Realisation from exports

For the period May 2000 to February 2001, ONGC exported around 0.3 million tonnes of naphtha with billing rate of Rs 11995.60/MT (28.25 $/bbl) which is very reasonable given that average Middle East naphtha fob in that period was 27.94 $/bbl (11862.76 Rs/MT). However, due to various expenses, the net realisation over the period amounted to Rs 10080 per tonne without demurrage and canalising commission and Rs 9820/MT with demurrage and canalising commission.

This difference between the billing rate and the net realisation is due to various costs involved in exporting naphtha. The major variable costs are-

1. SBM Charges
2. Pipeline Charges
3. Wharfage

At various crude prices, the price realised by ONGC by exporting naphtha itself will be the export parity price as charged by OMCs, exclusive of marketing margin at Hazira, calculated in table 16.12.

The expenses considered exclude the canalising commission since recently ONGC has been exporting naphtha all by itself.

However, the price realised by exports can be increased if it is in a position to export a larger quantum of naphtha at one time due to longer notice period that can facilitate global tenders against the current practice of limited tenders and due to lower freight per MT for large vessels.

From Hazira, ONGC exports naphtha using the Reliance SBM that has the capacity to handle cargo upto 50,000 tonnes. To export a cargo of 50,000 tonnes at one go, a storage capacity of at least 75,000 tonnes is needed. The current total storage capacity for naphtha at Hazira is 99000 cubic meters which roughly translates into 72,000 tonnes but the operating capacity is only 57,000 tonnes. At any given time, one tank has to be kept for receipt of product from Kerosene Recovery Unit and one tank under despatch to local/rail fed consumers. This leaves only 38,000 tonnes of capacity that could be used for exporting naphtha. Thus, if ONGC has to increase the size of export parcels to 50,000 tonnes, it has to invest in the storage capacity at Hazira.

We can thus say that to become a serious player in the export market, ONGC must have adequate infrastructure at the export port, which is most likely to be Hazira. All this involves substantial time and cost and depends on the long-term production profile since infrastructural investments have a long pay-off period. Thus benefits and costs of investment in extra storage capacity must be weighed against each other in order to decide the desirability of extra storage.

Summary of options

Table 16.14 Current Status

	Price realisable (Rs/MT)	Quantity (tonnes/month)	Revenue (Rs million)
Sales to OMCs	12010	75849#	910
Direct Sales	10494	29963#	314
Exports through IOC	9820	30698*	301

For the month of October 2001

* For the period May 2000 to February 2001

Table 16.15 Summary of all options

Options	Benefits	Costs	Price realisable
1) Renegotiate with OMCs			
a) Share in marketing margin of OMCs	Higher price realisation.	Greater offtake uncertainty	Import/Export parity price + Share in marketing margin
	No extra administrative efforts		
b) Long term purchase contract	No extra administrative efforts.	Lower price realisation	Lower than Import/Export parity price
2) Sell naphtha directly through long term contracts	Reduced uncertainty of offtake	Increased administrative efforts.	Non Availability of gas Either import parity price or export parity price
		Direct competition with OMCs.	Availability of gas Imputed value of naphtha versus LNG at various locations.
3) Vertical Diversification			
a) Acquiring marketing company	Internalisation of full marketing margin.	Acquisition cost is likely to be high.	Import/Export parity price + Full marketing margin
	Better export realisation at Uran.		
b) Setting up a plant using naphtha as a raw material	No need for any selling effort.	May have to buy naphtha some years down the line	NA
	No reliance on any OMC.	High initial capital investment.	
		Extra administrative costs.	
	No fear of reduction in naphtha prices due to LNG.	Multiplicity of contracts.	
4) Bypassing the naphtha production	No uncertainty regarding offtake.	Foregoing of margins on SKO and Heavy cut.	NA
		Have to sell NGL which may face the same problem.	
		Other costs associated with shutdown of operations.	

Options	Benefits	Costs	Price realisable
5) Export naphtha directly	No reliance on domestic market which is projected to be surplus in naphtha. No domestic spot sales on distress prices. Equal, if not more, than domestic realisation if the pricing is based on export parity prices Benefits of coastal location. Already has some experience in exports. Larger storage capacity will give bargaining power and reduce the spot sales.	A larger storage capacity to the extent of 37,000 tonnes at the port may be required to have better realisation.	Export parity price

Concluding remarks

From the foregoing it is apparent that ONGC does not have too many options. Naphtha will continue to be surplus in the country; OMCs have their own sources to maintain while ONGC's naphtha production is located mainly in the western region and currently they have no marketing infrastrucutre.

The following table shows the prices Ex-Hazira, exclusive of any marketing margin, under different options at crude price of 25 $/bbl, the expected long term average price of the OPEC's target crude oil price band of 22 to 28 $/bbl.

Table 16.16 Comparison of prices

Pricing basis	Price (Rs/MT)
Import parity price	12235
Export parity price	10512
Imputed value of naphtha versus LNG	9445

The following strategy is therefore recommended:

a) While ONGC may try and negotiate for a share of marketing margins it unlikely that OMCs will agree as has been in the case in the past. However, the import parity price of Rs.12,235 per MT is an attractive one and ONGC should attempt to enter into long term contracts with the OMCs even if it has to give a small discount on this price.

b) Acquisition of either BPCL or HPCL by ONGC will provide it the marketing infrastrucure it needs and additional security for absorption of part of its production.

c) To compete against LNG, not only ONGC but OMCs also will have to drop their prices substantially and depending on the supply demand balance this may be necessary if there are uncontainable surpluses.

d) Export parity price on naphtha is about 14% lower than the import parity price but 10% higher than its imputed value vs. LNG. Therefore export of naphtha must always remain a second option if ONGC cannot realise the import parity price from OMCs or there is an uncontainable surplus. However to improve price realisations, ONGC must increase its storage capacity at Hazira (to load larger tanker parcel sizes) and use international trading instruments eg. options, hedging etc. to realise the best value for its export naphtha. Even if some concession is made for the fact that naphtha produced at Uran is ideal for petrochemical plants and hence may command a premium in the international market, the export realisation is expected to go up by Rs 230/MT, given the average premium of $5/MT. This would still keep the export parity prices to about 87% of the import parity prices.

Part – 4
Risk Management Issues

17 Issues in hedging

Stability in cash flows and consistency in profit levels are two important long-term objectives of any company. Liquidity to maintain working capital and to meet the short term obligations require stability in cash flows whereas appraising the long term investment projects require forecasting the profit margins for the company over an extended time frame. Thus, "risk management", to reduce the variations in cash flows and profit levels, has come to acquire an important place in modern corporate management.

This chapter then seeks to broadly present various issues related to risk management and hedging in particular.

Issues in hedging

ONGC is primarily an oil exploration and production company though it has also developed a portfolio of refined products like LPG, Naphtha and Kerosene. In the year 2000-01, revenue from sale of crude oil accounted for about 61% of the total sales revenue[a]. And with the prices of the petroleum products also linked to the crude prices, it means that virtually all revenue is linked to the crude oil prices. Thus, it is evident that the biggest risk ONGC faces is the volatility in crude prices. However, there are few other important factors that are important while analysing the need for hedging. These are - the ownership structure of the company, the ownership structure in the industry as a whole and the risk return perception of the investors and markets alike. These issues are discussed below.

Volatility in crude prices

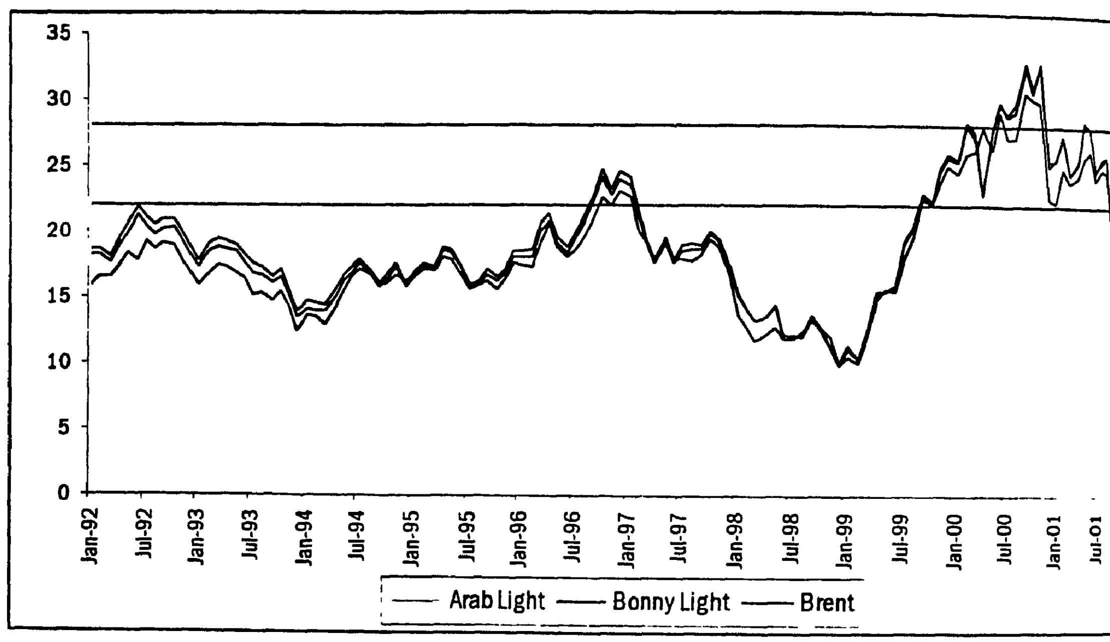
ONGC produces about 23 MMT of crude every year. An intermonth fall of about $1/bbl in crude prices internationally will lead to a fall in revenue to the tune of Rs 646 million[b], which is about 5% of the monthly revenue from crude oil sales. Thus, it is apparent that one of the important factors determining the need for hedging is the perceived volatility in crude prices.

[a] ONGC Annual Report 2000-2001, Page 15
[b] Assuming equal deliveries in each month and an exchange rate of $1 = Rs 46

Three important crudes from India's point of view are Arab Light, Bonny Light and Brent. Arab Light and Bonny Light are important because of their presence in the India's imported crudes basket. Brent, though not used extensively by the Indian refineries, is important because it is the marker crude for pricing the sweet crudes world-wide.

The following figure show the monthly movement in crude prices of these three crudes for the 10 year period extending from January 1992 to December 2001, compiled from various issues of OPEC Bulletin.

Figure 17.1 Variation in crude oil prices (Prices in $/bbl)



As these figures show that for the past many months, prices have been in the OPEC's target range of $22-$28/bbl. Given the fact that many OPEC countries balance their budget within this price range and given the influence of OPEC on world oil production, it can be said that the prices would generally remain in the OPEC's target price band for the foreseeable future. This will significantly reduce the price risk for ONGC.

It is also argued that crude oil prices have a mean reverting trend in the long run, which again undermines the need for hedging. A counter argument forwarded by various brokers like Citibank and Global Commodities[c] is that even if the crude oil move within the target band, the fluctuations within give

[c] The views of these financial intermediaries are given in Annexure 17.1.

enough reason to hedge. But as explained below, this argument does not hold true in the context of the ownership structure of the Indian oil industry.

Ownership structure of the Indian oil industry

The present equity structure of major companies in the Indian oil market is heavily represented by the government of India[d]. The two upstream companies, ONGC and OIL, are almost entirely owned by government with some cross holdings by other government agencies/companies. Government also holds significant equity and management control of downstream majors like IOC, HPCL and BPCL.

This means that the sale of crude oil by upstream companies to refineries is mainly a transfer by one public sector organisation to another, both under the purview of one ministry. In such a structure, fall in prices will benefit one entity while harming the other with overall gains/losses being passed off to the government since it is the major shareholder or to the consumer if free pricing is followed.

Indulging in hedging, according to the owner may be, in such a structure only ends up raising the costs of the final products for the consumer and outgo of revenue from government reserves to the intermediary. If ONGC sells its crude oil to IOC and or to some other public sector refinery, after hedging its sales, it raises the price of crude oil for IOC since the hedging premium will also be built into the prices. Now, if IOC also hedges the sale of its petroleum products, it will again raise the prices for the final consumer since IOC will also build in the premium for hedging in these prices. Thus, the final prices will rise on two accounts, first on the account of premium paid by ONGC and then again on account of premium paid by IOC. If the prices are not raised to full extent due to price elasticity restrictions, this will involve a loss for the government and the main beneficiary will be the broker who will earn premium on both accounts. The question than need to be asked is that whether there is substantial price risk so as to warrant an insurance payment to the financial intermediary at the cost of increased prices for the final consumer?

[d] As per the latest annual reports, following gives the share of government of India in these companies.

1. ONGC – 84.11%
2. IOC – 82.03% (To be reduced to 74.5% after the Rs 1600 crores IPO)
3. HPCL – 51.01%
4. BPCL – 66.2% (To be reduced to 56% after the Rs 1000 crore IPO)

To the extent that some of the bulk buyers like fertiliser plants are also public sector companies, these increased prices will only raise the input costs for them and hence raises the costs of essential commodities like urea.

Thus, the ownership structure of the industry should be kept in mind while deciding on hedging and as and when the structure changes, a rethink on the same may be required.

Management issues

There are some management issues that need to be tackled before the organisation decides for hedging. The process of hedging is as dynamic as the market itself. Quick decision-making and risk taking are the two prerequisites for profitable hedging. Normally public sector companies are not known for providing environment conducive to breed these qualities in their management.

In a public sector set up, mistakes tend to be magnified because the money involved is state's money whereas successes go unrewarded. This attitude acts as a dampener on quick decision-making since few decisions in the initial years will go wrong. Thus, decision-making in such an environment tends to be very hierarchical and cautious. This goes counter to the risk taking environment where the motive behind a decision is appreciated and not the result.

Moreover, the incentive structure in the public sector organisation does not promote risk taking managerial initiatives. Such initiatives are central to the risk management strategy that requires quick decisions, which may or may not yield desirable results.

This is not to suggest that such an environment cannot be developed. Detailed guidelines, which are both binding as well as broad and policies that lay down the permissible risk exposure level certainly help in the objective of the hedging. It is important that ONGC keeps this issue in mind while deciding on hedging.

Participation by international oil majors in hedging markets

International exploration and development companies are not known to be actively involved in hedging. One of the principle reasons is the risk return trade off perceived by the investors and the markets alike. This means that higher the risk company is taking, the higher is the return it is expected to generate. If an oil company hedges its crude oil sales, it is locking the price it will get for it, irrespective of the actual price in the market. Thus, in effect, it is eliminating the risk inherent in oil market. This then precludes the opportunity of higher

returns on its crude oil and will reduce the overall organisational returns, which will be against the expectations of its investors and the market. Management not taking the risk tends to drive away the investor from the company. This will reduce the return on the equity of the company due to depressed expectations. This is best echoed by Unocal in the 1999 Annual Report-

"We have also revised our hedging policy, following losses from our 1999 corporate hedging programme of about $29 million after-tax. As oil and gas prices plunged late in 1998, we put some "collar" hedges in place to protect the cash flows needed to invest in our most important exploration programs. When prices moved up significantly, these hedges reduced our ability to benefit fully. In the future, we will not employ corporate hedging programs that can limit our participation in rising commodity prices."

Thus, large corporations with wide spread investor base are much averse to hedging than small corporations that are much interested in short term profits to attract more investors.

Refineries and traders on the other hand are very active in the hedging markets. These can be either pure trading companies like Enron or trading arms of an integrated oil company like BP. This is because their business is to maximise, or at least protect, the margins involved in the process. Their costs as well as revenues are very volatile and hence are the underlying margins. Moreover, refineries typically operate on a thin and tight margin that makes them more vulnerable to even a slight change in either crude or petroleum product prices. And if the refineries are unable to pass off the entire increase in costs of procurement to the consumer due to either competition or price-elasticity of demand or slow demand, the margins come under severe pressure. Exploration and development companies do not face highly volatile costs and, more often than not, they can pass off the increase in prices to the refineries. So they are less concerned about the underlying margins and hence may be less interested in hedging. This is best captured in the statement made by Shell in its latest annual report –

"Apart from forward foreign exchange contracts to meet known commitments, the use of derivative financial instruments by most group companies is not permitted by their treasury policy..... Other than in exceptional cases, the use of derivative instruments is generally confined to specialist oil trading.."

But futures markets like IPE and NYMEX have reported manifold increase in trading in the crude oil futures and options. In fact, the Brent contract traded on IPE is being increasingly used for the purpose of setting price of crude in the

physical market. The main participants in these markets are trading companies and the so-called "Wall Street Refineries" whose main purpose is to benefit from arbitrage opportunities.

Participation by exporting countries

The major producer countries, organised under OPEC, are not very active in the hedging markets. This is primarily due to the power OPEC has in influencing the price of crude oil to its advantage. Moreover, ever since the control of crude oil passed over from oil majors to the national oil companies of the OPEC countries, these companies have entered into long term supply contracts with the national oil companies of the consuming countries and have little presence in the spot market. That OPEC countries prefer stable crude prices is also evident from the OPEC's stated objective of maintaining the crude prices within a target band of $22-28/bbl.

Middle East accounted for 50.3% of the total world crude oil exports from the producing countries. Since Middle East crude is sold under the long-term contracts, this means that about 50% of the crude oil traded world-wide is not hedged. These long term contracts bind the importing country national oil company as well as the exporting country national oil company and allows little room to operate on the spot market. This is manifested in the fact that spot trade forms only a small percentage of the total world crude oil trade. The world spot trade in concentrated in few marker crudes like Brent, Dubai and WTI, which represent about 3-4% of the international trade in crude[e]. The rest of the traded crude oil moves under term contracts. Moreover, the spot trade is concentrated in few regions of the world.

The spot trade in Asia is also very thin. The bulk of crude oil moves either through integrated channels, between state oil corporations of the same country or through term contracts with regional buyers. Annexure 17.2 shows the number of reported spot deals from 1986 to 1995 for many Asian countries. As shown in this table, in 1995, there was on average only one deal per calendar day or less than 1.4 per trading day. Annexure 17.3 shows the reported spot trade for many Asian grades. As the table shows, only trade in Minas exceeds two deals per week, with Tapis following one deal per week. No Australian crude has spot liquidity and even that in Gippsland fell in the 1990s.

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[e] Paul Horsnell and Robert Mabro: "Oil Markets and Prices" Oxford Institute for Energy Studies, Oxford University Press

Concluding remarks

From the above analysis, it can be concluded that the need for hedging varies from company to company. The starting point for any risk management strategy is an analysis and quantification of the risks an organisation is facing and the sensitivity of the project evaluation to the underlying prices in the international market. From the precluding analysis, it can be said that ONGC does not face any substantial price risk in the view of price cartel OPEC. In fact, ONGC seems to gain from the pricing strategies of OPEC.

Additionally, the organisational structure of ONGC does not encourage hedging since government is the majority shareholder in the company.

Next, the instruments and hence the markets to be used for risk management need to be identified. Exploration and production companies are primarily engaged in the Over-The-Counter market but it should be viewed as complementary to Recognised Investment Exchanges (RIE). And a big company is more active in the Over-The-Counter market than a small company. A successful risk management may require presence in both the markets. These instruments are essentially like an insurance plan for the revenue. More the sensitivity of the ongoing and future projects to the variations in the crude oil prices, the greater is the need for and hence the premium on risk management tools.

One option for ONGC is to enter in the hedging market through a financial intermediary or through a separate trading arm within the conglomerate but at an arms' length with the exploration and development function to ensure transparency and accountability. Involvement through financial intermediary will involve transaction costs irrespective of the outcome of the hedge which may weigh heavy on the balance sheet. Creating a separate trading arm with enough expertise is likely to be a long drawn procedure with an equally committed management. This is the strategy followed by integrated oil companies like BP and Chevron-Texaco, which have established separate trading arms for this purpose only.

18 Conclusions

PART 1 – CRUDE OIL

Introduction

The upstream oil sector of India is dominated by the two National Oil Companies – Oil and Natural Gas Corporation Limited and Oil India Limited, with a share of about 88% of country's present oil and gas production. While ONGC produces nearly 77% of indigenous crude oil and 82% of country's gas production, OIL's share of 10% of indigenous oil and 6% of gas production is confined mainly to its areas of operation in Assam, Arunachal Pradesh and Rajasthan. Oil and gas production by OIL in 1999-00 had been 3.3 MMT and 1729 MMCM respectively. Whereas oil and gas production by ONGC in the same year had been over 24 MMT and 23252 MMCM respectively.

The Xth Plan targets a domestic oil production of about 32 MMT by 2006/7, whereas the demand is expected to reach about 214 MMT. This gap of 85% is to be bridged by imports. ONGC targets an oil production of about 25 MMT by 2006/7. Any shortfall from domestic production targets will further increase the import dependence.

Demand/Supply forecasts

The share of oil in primary energy consumption has remained unchanged at 40% from 1990 to 2000. Almost all the regions have experienced a decline in the share of oil with the sole exception of Asia-Pacific. The largest decline has occurred in Former Soviet Union (FSU) where the share of oil declined from 30% to 19% followed by Middle East where the share declined from 64% to 54%. Asia-Pacific, on the other hand, has seen an increase in the share of oil from 37% to 41%.

According to International Energy Outlook (IEO) 2002, oil production is projected to increase to 87.9 million bbl per day by 2005 and to 97.4 million bbl per day by 2010. This implies an annual growth rate of 4% from 2000 to 2005. Likewise, consumption is projected to grow from 84.9 million barrels per day by 2005 to 94.9 million barrels per day by 2010.

Sweet crude demand/supply

North America, Europe and Asia-Pacific are projected to be net importers of crude oil while Middle East, Former Soviet Union, Africa and South and Central America are projected to be net exporters.

The following table shows the resulting demand supply balance of sweet crude for the coming decade.

Table 18.1 Demand-supply outlook for sweet crude (million tonnes)

	2005	2010
Demand	552	635
Supply	558	692
Net Surplus	6	58

Approach to marketing strategy

According to the existing Export-Import policy ONGC may not be in a position to export crude oil easily because of infrastructure constraints & also canalisation role still continue to be with IOC. Even if these constraints are tide over by ONGC, ONGC is not likely to get price better than the FOB price. This fact is known to most of the refineries and therefore they may be expecting that ONGC is not likely to enter international market for export of its crude.

Though ONGC may be expecting to move towards import parity prices while fixing its price for crude from April '02, it will not be easy for it to convince the refinery. Similarly refinery may not be justified in insisting that they will not pay more than what ONGC is presently getting from the OCC because ONGC will be committed to pay certain liabilities to the Government of India under various rule out of the amount which they get from refineries.

The pricing strategy is composed of two parts – base value and premiums/discounts as may be applicable to the crude depending on the field specific factors.

The various options for base price that have been examined are:

Option A. ONGC receives fob of comparable international crude and pays central sales tax.

Option B. ONGC receives fob of comparable international crude but does not pay central sales tax

Option C. ONGC receives import parity price of comparable international crude and does not pay central sales tax

Option D. ONGC receives import parity price of comparable international crude and pays central sales tax.

In addition to deciding on the basic price for crude from the above mentioned four options, the report has also worked out estimates of premiums and discounts applicable for different crudes. These premiums and discounts are calculated in view of the strengths and weaknesses of ONGC vis-à-vis refineries.

The resulting price structure for crude has been examined keeping in mind the exploration commitment of ONGC. As per the Annual Report of ONGC for 2000-01, it plans to invest Rs 47590 million to increase the reserves by 61.53 million tonnes in the next 20 years. This works out as $ 2.3/bbl.

The results of the field wise price calculations are summarised below.

Field wise strategy

Bombay High

BH crude is in a position to command a premium over and above the basic price from all the refineries. Applying this premium to all the four options for basic price for BH crude yields the following surplus for ONGC.

Table 18.2 Surplus for ONGC from Bombay High field ($/bbl)

Refinery	Option A	Option B	Option C	Option D
BPCL - Mumbai	1.86	2.37	5.44	4.81
HPCL - Mumbai	1.86	2.37	5.44	4.82
Koyali	1.40	1.91	4.98	4.34
Mathura	1.40	1.91	4.98	4.35
Panipat	1.41	1.92	4.99	4.36
Kochi	1.85	2.36	5.43	4.80
Vizag	1.88	2.38	5.45	4.82
MRPL	1.86	2.37	5.44	4.81
Chennai	1.88	2.38	5.45	4.82

Given the ONGC's exploration commitment of $2.3/bbl, it seems that ONGC should negotiate for Option C. However it should accept no less than Option D which means that it should get the import parity price for BH and may pay the sales tax on behalf of the refineries.

Gujarat crudes

ONGC will probably have to give a discount to Koyali refinery for its North and South Gujarat crudes. Applying this discount to all the four options and deducting the various charges ONGC will have to pay, the following surpluses emerge.

Table 18.3 Surplus for ONGC from Gujarat fields ($/bbl)

Refinery	Option A	Option B	Option C	Option D
Koyali	0.57	1.08	4.17	3.53

As this table shows, Option A and Option B are not sustainable for ONGC. Under Option D, given the exploration commitment of 2.3 $/bbl, the net left is $1.23/bbl which gives 34.8% return to ONGC which is very fair. Thus, ONGC should not accept anything less than Option D.

Cauvery basin

ONGC may not get the import parity price for its crude due to prohibitive costs of moving crude to alternate refineries. It may have to negotiate for FOB price only. Applying this discount to all the four options for setting the base price, the following surpluses emerge.

Table 18.4 Surplus for ONGC from Cauvery basin ($/bbl)

Refinery	Option A	Option B
CBU	1.48	1.97

This table shows that if ONGC were to get the FOB price for its crude, then even if it gets the full premium as estimated above, it will find it difficult to generate enough surplus from this region.

Under Option B, the surplus left is $ 1.97/bbl which is $ 0.33/bbl less than the surplus of $ 2.3/bbl required by ONGC to fund its exploration activities. Thus, ONGC should try to negotiate at least that price at which $ 0.33/bbl higher than the price under Option D.

Krishna-Godavari basin crude

ONGC has got no option but to sell this crude to the Vizag refinery. Vizag, on the other hand, has two other sources of crude procurement, one of which is indigenous and is contributing significant quantity. Thus, it is very unlikely that ONGC will get import parity price for KG crude. But at the same time, there is no reason why ONGC should get anything less than the FOB of the benchmarked crude. Thus, FOB represents the minimum base price for ONGC to negotiate for.

If the base price is indeed set at FOB, then the surplus left for ONGC after meeting all the claims like tax, cess, and other direct and indirect costs is shown below.

Table 18.5 Surplus for ONGC from KG basin ($/bbl)

Refinery	Option A	Option B
Vizag refinery	0.75	1.24

As this table shows, this pricing option is not sustainable for ONGC. It needs at least $2.3/bbl to fund its commitment in E&P but this field will not generate enough surplus for the same. Thus, ONGC should negotiate for at least that price which enhances the surplus by $1.06/bbl. This is not a big amount if the crude is priced at FOB since then the refinery will be saving all the transportation charges and other charges incurred in importing the crude and given the fact that there is a margin of $3.36/bbl between FOB and Import parity pricing.

North Eastern crude

Given the fact that ONGC does not have any alternate option to sell its crude and given the fact that ONGC's crudes are not of international quality, it will be difficult for it to demand import parity price for its crude. The refineries are in a better position to source the crude either from OIL or take the imported crude and hence will not give import parity price to ONGC. Thus, out of the four pricing options mentioned earlier, only two are possible – those based on FOB.

The surplus left for ONGC under the two pricing options are shown below.

Table 18.6 Surplus for ONGC from North East fields ($/bbl)

Refinery	Option A	Option B
Barauni	1.26	1.77
BRPL	1.26	1.77
Guwahati	1.26	1.77
NRL	1.26	1.77
Digboi	1.26	1.77

This table shows that surplus generated in North East may not be enough if the pricing is done on FOB basis. However, if ONGC can negotiate for an additional $ 0.53/bbl under Option B, it can make the required surplus of $ 2.3/bbl.

PART 2 – NATURAL GAS

Introduction

Domestic gas production at present is about 78 MMCMD. In contrast, gas demand estimations show that existing gas demand from power, fertiliser, industrial units like cement, paper and pulp and glass and captive generation is

about 105.43 MMCMD. This is projected to increase to 136.93 MMCMD by 2006/7. Thus implying a widening gap between domestic gas supply and demand.

In India, 80% of the gas is consumed by power and fertiliser sectors. In future too these sectors will dominate the demand scenario. Bulk of the demand will be generated from the power sector which is projected to increase from 49.37 MMCMD at present to about 72 MMCMD by 2006/7.

Analysis of imputed values of gas reveal that at a gas price of $4.5/MMBtu and $3.5/MMBtu, gas demand in 2006 will be about 86 and 122 MMCMD respectively. The objective of the marketing strategy of gas is to maximise the netback to ONGC from selling gas.

Pricing strategy

Domestic gas price is expected to be linked to full parity with fuel oil in the near future. The gas price should get another boost in 2004 when LNG arrives at Gujarat.

The revision to full parity with fuel oil would not be effective unless the ceiling price is revised upward. ONGC should try to negotiate a high ceiling price. It would be more feasible for ONGC to negotiate a better fuel oil basket, choosing only low sulphur fuel oils, altering the weight in favour of low sulphur fuel oils in the basket and by changing fob prices to cif. So long as the ceiling price is acceptable, the consumers may be less sensitive to a higher price within the ceiling.

With the advent of LNG if domestic gas is pooled with LNG, the proportion of costly gas to domestic gas will have substantial impact on netbacks for ONGC. Thus ONGC must be fully involved in the price fixing exercise.

ONGC would be free to get a better price for gas from NELP blocks. When LNG becomes available, the price of this gas could be raised to import parity. However, most of this gas is expected to be found around Gujarat or Andhra Pradesh where gas-to-gas competition may keep the price down. In view of the possibility of increasing the gas price, it would be prudent not to sell this gas on long term contracts. At least, the price should be kept flexible.

Bulk selling to GAIL or other marketing agencies may be more feasible in cases where the marketing risk appears to be large. The price for bulk sales would be fuel oil linked. Again, the choice of fuel oils would be important, as would be the price ceiling or the linkage. These could vary between regions depending on the purchasing power of the customer. For gas sold to GAIL, prices are to be fixed by the government and likely to reach fuel oil parity, thus

subject to variability depending on behaviour of crude oil prices. Where ONGC is free to price the gas a compromise acceptable to both the buyer and the seller would be a variable price subject to a floor and a ceiling. Generally, the ceiling would be dictated by the cost of alternative fuels to the buyer whereas the floor would be a function of the production cost.

Gas consumers in India may have difficulties in signing long term contracts with stiff take-or-pay provisions. Gas suppliers who depend on project finance for developing their fields may find such terms unavoidable. ONGC could offer more flexible contract conditions if that leads to a higher market share. In some cases, a similar advantage could be derived by offering Rupee prices in stead of Dollar denominated prices.

PART 3 – VALUE ADDED PRODUCTS

LPG

Given the market scenario, it is recommended that ONGC should opt for continuing current marketing arrangements with OMCs. However, post deregulation, these arrangements should be backed by commercial agreements, clearly specifying delivery points, volumes, prices, credit terms, etc.

There is a huge difference between the current price realised by ONGC and the prevailing import parity prices for LPG. ONGC should aggressively negotiate to hike its realisation to near import parity levels. Slight discounts by ONGC vis-à-vis the import parity price would assure 100% offtake of its production by OMCs. Even with discounts to import parity prices, the net gain for ONGC would be substantial, enhancing its profitability considerably.

Naphtha

From the demand and supply analysis, it is apparent that ONGC does not have too many options. Naphtha will continue to be surplus in the country; OMCs have their own sources to maintain while ONGC's naphtha production is located mainly in the western region and currently they have no marketing infrastructure.

The import parity price of Rs.12,235 per MT is an attractive one and ONGC should attempt to enter into long term contracts with the OMCs even if it has to give a small discount on this price. To compete against LNG, not only ONGC but OMCs also will have to drop their prices substantially and depending on the

supply demand balance this may be necessary if there are uncontainable surpluses.

Export parity price on naphtha is about 14% lower than the import parity price but 10% higher than its imputed value vs. LNG. Therefore export of naphtha must always remain a second option if ONGC cannot realise the import parity price from OMCs or there is an uncontainable surplus.

PART 4 – RISK MANAGEMENT ISSUES

From the above analysis, it can be concluded that the need for hedging varies from company to company. The starting point for any risk management strategy is an analysis and quantification of the risks an organisation is facing and the sensitivity of the project evaluation to the underlying prices in the international market. From the precluding analysis, it can be said that ONGC does not face any substantial price risk in the view of price cartel OPEC. In fact, ONGC seems to gain from the pricing strategies of OPEC.

Additionally, the organisational structure of ONGC does not encourage hedging since government is the majority shareholder in the company.

Next, the instruments and hence the markets to be used for risk management need to be identified. Exploration and production companies are primarily engaged in the Over-The-Counter market but it should be viewed as complementary to Recognised Investment Exchanges (RIE). And a big company is more active in the Over-The-Counter market than a small company. A successful risk management may require presence in both the markets. These instruments are essentially like an insurance plan for the revenue. More the sensitivity of the ongoing and future projects to the variations in the crude oil prices, the greater is the need for and hence the premium on risk management tools.

One option for ONGC is to enter in the hedging market through a financial intermediary or through a separate trading arm within the conglomerate but at an arms' length with the exploration and development function to ensure transparency and accountability. Involvement through financial intermediary will involve transaction costs irrespective of the outcome of the hedge which may weigh heavy on the balance sheet.

ANNEXURES

Annexures
Part 1
Crude Oil

Annexure 2.1
World oil reserves and production (2001)

	Proven Reserves, 2001 (Thousand million barrels)	Share	Production, 2001 (Thousand barrels/day)	Share	R/P ratio (Years)
North America	63.9	6.1	14040	18.3	13.5
S & C America	96.8	9.1	7001	9.9	38.8
Europe	18.7	1.8	6808	9.0	7.8
FSU	65.4	6.2	8652	11.8	21.1
Middle east	685.6	65.3	22233	30	86.8
Africa	76.7	7.3	7814	10.3	27.4
Asia Pacific	43.8	4.2	7943	10.6	15.6
World	1050.0	100	74493	100	40.3
Of which OECD	85.0	8.1	21462	28.1	11.5
OPEC	818.8	77.8	30181	40.7	76.6
Non-OPEC	165.8	15.9	35660	47.4	13.3

Source. BP Statistical Review of World Energy, 2002

Annexure 2.2
Major oil producers and consumers (2001)

Country	Production (000b/d)	Share of total	Country	Consumption (000b/d)	Share of total
Saudi Arabia	8768	11.77	USA	19633	26.08
USA	7717	10.36	Japan	5427	7.21
Russia	7056	9.47	China	5041	6.70
Iran	3688	4.95	Germany	2804	3.72
Mexico	3560	4.78	Russia	2456	3.26
Venezuela	3414	4.58	Korea	2235	2.97
Norway	3308	4.44	India	2072	2.75
China	3418	4.59	France	2032	2.70
Canada	2763	3.71	Italy	1946	2.58
UK	2503	3.36	Canada	1941	2.58
Total World	74493		Total World	75291	

Note. The difference between production and consumption totals is due to stock changes, consumption of non-petroleum additives, and disparities in definition, measurement and conversion of supply, demand data.

Annexure 2.3
IEO projections of oil production and consumption by 2020

Table 2.3.1 World oil production (reference case)

		2005	2010	2015	2020
OPEC					
Persian Gulf					
	Iran	4	4.3	4.6	4.8
	Iraq	3.1	3.8	4.7	5.8
	Kuwait	2.8	3.5	4.1	5
	Qatar	0.5	0.6	0.7	0.7
	Saudi Arabia	12.6	14.7	18.4	23.1
	UAE	3	3.5	4.4	5.1
Total Persian Gulf		**26**	**30.4**	**36.9**	**44.5**
Other OPEC					
	Algeria	1.9	2.1	2.3	2.5
	Indonesia	1.5	1.5	1.5	1.5
	Libya	2.1	2.5	2.8	3.2
	Nigeria	2.8	3.2	4	4.7
	Venezuela	4.2	4.6	5	6
Total Other OPEC		**12.5**	**13.9**	**15.6**	**17.9**
Total OPEC		**38.5**	**44.3**	**52.5**	**62.4**
Non-OPEC					
Industrialized					
	United States	9	8.7	9	9.3
	Canada	3	3.2	3.4	3.5
	Mexico	4.1	4.2	4.4	4.4
	Australia	0.8	0.8	0.8	0.8
	North Sea	6.6	6.5	6.2	6
	Other	0.8	0.8	0.8	0.7
Total Industrialized		**24.3**	**24.2**	**24.6**	**24.7**
Eurasia					
	China	3.1	3.1	3	3
	FSU	9.6	11.9	13.6	14.8
	Eatsern Europe	0.3	0.3	0.3	0.4
Total Eurasia		**13**	**15.3**	**16.9**	**18.2**
Other non-OPEC					
	C&S America	4.2	4.8	5.5	6.4
	Middle East	2.2	2.4	2.5	2.4
	Africa	3.1	3.8	4.6	5.8
	Asia	2.6	2.6	2.6	2.5
Total Other non-OPEC		**12.1**	**13.6**	**15.2**	**17.1**
Total Non-OPEC		**49.4**	**53.1**	**56.7**	**60**
Total World		**87.9**	**97.4**	**109**	**122**

Source. International Energy Outlook, 2002

Table 2.3.2 World oil consumption (reference case)

		2005	2010	2015	2020
Industrialized Countries					
North America		**25.6**	**27.6**	**29.9**	**32.2**
	United States	21.2	22.7	24.3	25.8
	Canada	2.1	2.1	2.2	2.2
	Mexico	2.3	2.8	3.4	4.2
Western Europe		**14.7**	**15.1**	**15.3**	**15.4**
	United Kingdom	2	2.1	2.2	2.2
	France	2.1	2.2	2.2	2.2
	Germany	3	3.1	3.1	3.1
	Italy	2.1	2.2	2.2	2.2
	Netherlands	0.9	0.9	0.9	0.9
	Other Western Europe	4.6	4.6	4.7	4.8
Industrialized Asia		7.1	7.3	7.6	7.7
	Japan	5.7	5.8	5.9	5.9
	Australasia	1.4	1.5	1.7	1.8
Total Industrialized		**47.4**	**50**	**52.8**	**55.3**
EE/FSU					
	Former Soviet Union	4.9	5.6	6.9	7.8
	Eastern Europe	1.6	1.6	1.7	1.7
Total EE/FSU		**6.5**	7.2	**8.6**	**9.5**
Developing Countries					
Developing Asia		**16.7**	**20.5**	**25**	**29.7**
	China	5.3	6.7	8.5	10.4
	India	2.6	3.4	4.5	5.8
	South Korea	2.5	2.8	3.1	3.3
	Other Asia	6.3	7.6	8.9	10.2
Middle East		**5.6**	**6.8**	**8.2**	**10.3**
	Turkey	0.8	1	1.1	1.3
	Other Middle East	4.8	5.8	7.1	9
Africa		**3.4**	**4**	**4.6**	**5.4**
C and S America		**5.3**	**6.4**	**7.7**	**9.3**
	Brazil	2.3	2.9	3.6	4.5
	Others	3	3.5	4.1	4.8
Total Developing		**31**	37.7	**45.5**	**54.7**
Total World		84.9	94.9	106.9	119.5

Source. International Energy Outlook, 2002

Annexure 2.4
Oil trade movements (1995-2001) (000bbls/d)

	1995	1996	1997	1998	1999	2000	2001
Imports							
USA	8831	9400	9907	10382	10550	11092	11618
Europe	10436	10472	10421	11017	10670	11070	11531
Japan	5581	5685	5735	5259	5346	5329	5202
Rest of World	11562	12764	13721	13432	14157	14911	15403
Total World	36410	38321	39784	40090	40723	42402	43754
Exports							
USA	949	978	976	1011	956	890	910
Canada	1402	1484	1492	1603	1520	1703	1804
Mexico	1422	1656	1767	1770	1739	1814	1882
S. & Cent. America	2797	3011	3219	3240	3145	3079	3143
Europe	1472	1540	1463	1344	1851	1967	1947
Former Soviet Union	2731	3239	3413	3569	4019	4273	4679
Middle East	16651	17170	18184	18702	18341	18944	19098
North Africa	2696	2756	2743	2712	2726	2732	2724
West Africa	2723	2916	3102	3094	2985	3293	3182
Asia Pacific	2576	2790	2735	2490	2650	2767	2879
Rest of World	991	781	690	555	791	940	1506
Total World	36410	38321	39784	40090	40723	42402	43754

Source. BP Statistical Review of World Energy, 2002

Annexure 4.1
Major crude oils from Middle East Gulf

Region	Crude	API	Sulphur (wt%)
The Middle East Six			
Iran	Iranian Light	32.56	1.50
	Iranian heavy	30.68	1.92
	Lavan Blend	33.71	1.83
	Sirri	30.9	2.3
	Foroozan	31.3	2.5
Iraq	Basra Light	32.56	2.18
	Kirkuk Blend	35.1	1.97
Kuwait	Kuwait	30.40	2.59
Qatar	Al Rayyan	24.51	3.26
	Al Shaheen	29.02	2.20
	Qatar Manne	35.3	1.57
Saudi Arabia	Arab Light	33.23	1.90
	Arab Medium	31.43	2.47
	Arab Heavy	27.85	2.81
UAE/Dubai	Dubai Export	31.14	1.94
UAE/Sharjah	Mubarek	46.15	0.28
UAE/Abu Dhabi	Asab	40.54	0.81
	Bu Hasa	39.09	0.77
	Murban	39.29	0.80
	Umm Shaif	37.4	1.51
	Upper Zakum	33.23	1.89
Other countries in the Gulf region			
Oman	Oman	33.80	1.14
Sudan	Nile Blend	34.87	0.04
Syria	Synan Light	36.25	0.74
Yemen	Marib Light	49.68	0.07
	Masila	31.05	0.54
Turkey	Turkish Indigenous	32.65	0.73

Source. BP Crude Assay Library reported by Haverly Systems

Annexure 4.2
Major crude oils from African countries

Region	Crude	API	Sulphur (wt%)	Pour point °C
Nigena	Bonny Light	37	0.1	-15
	Bonny Medium	25	0.2	-25
	Brass River	41	0.1	0
	Escravos	36	0.1	-12
	Forcados Blend	29.70	0.29	-20
	Odudu	30.86	0.17	-
	Pennington Light	36.60	0.07	6
	Qua Iboe	36	0.1	5
Ubya	Amna	36.1	0.15	24
	Boun	25.55	1.85	-
	Brega	40.4	0.21	-1
	Es Sahara	43.19	0.06	-
	Es Sider	36.7	0.37	7
	Sanr	38.3	0.18	-4
	Bu Attifel	44	0.03	30
	Zueitina	41	0.3	10
	Sirtica	43	0.4	-5
Algena	Saharan Blend	44	0.1	-30
	Zarzaitine Blend	43	0.1	-10
Angola	Cabinda	32.00	0.2	20
	Kiame	29.30	0.83	-
	Nemba	38.78	0.17	-
	Palanca	37.15	0.18	-
	Soyo Blend	34.00	0.2	20
Cameroon	Kole manne blend	35.00	0.3	-6
Congo	Djeno Blend	27	0.3	5
	N'Kossa	48.30	0.06	-
	Yombo	17.70	0.25	-
Zaire (former)	Zaire	30.7	0.16	25
Egypt	Seuz Blend	32	1.5	0
	Belayim	27	2.2	5
	Zaafarana	23.06	3.15	-
Gabon	Mandji	30.5	1.1	3
	Gamba	31.8	0.11	23
	LucinaManne	39.5	0.05	15
	Ogwendjo	36	0.71	18
	M'Bya	35	0.07	18
	Rabi	34	0.06	18
Tunisia	Ashtart	29	1.0	10
	Didon	34.00	0.82	-
	Rhemoura	31.24	0.89	-
	Tazerka	31.33	0.94	-

Source. Reports of Environmental Technology Center, BP Crude Assay Library reported by Haverly Systems and www.mbendi.co.za

Annexure 4.3
Major crude oils from North Sea region

Region	Crude	API	Sulphur (wt%)
United Kingdom	Brent	38.00	0.44
	Forties Blend	40.96	0.29
	Flotta Mix	36.85	0.82
	Fulmar 568C	41.48	0.24
	Maureen	35.90	0.33
Norway	Ekofisk	38.88	0.83
	Statfjord Snorre	37.76	0.30
	Oseberg	35.86	0.32
	Gullfaks	35.17	0.28

Source. BP Crude Assay Library reported by Haverly Systems

Annexure 4.4
Major crude oils from USA and Canada

Region	Crude	API	Sulphur (wt%)
USA	Alaska North Slope	29.57	1.08
	Bay Marchand	35.86	0.25
	Grand Isle	33.23	0.36
	High Island	37.46	0.27
	Light Louisiana Sweet	37.96	0.34
	Ostrica	32.84	0.28
	South Lousiana	32.84	0.30
	WTI	39.29	0.44
Canada	Bow River	24.85	2.48
	Cold Lake	22.98	3.19
	Fosterton	23.82	2.93
	Lloydminster Blend	22.47	2.96
Mexico	Isthmus	32.37	1.35
	Mars	28.39	2.15
	Maya	21.56	3.34
Venezuela	BCF - 17	16.20	2.31
	Bolivar Coast 24	23.40	1.85
	Maralago	20.90	3.38
	Mesa 30	29.48	1.03
	Santa Barbara	33.71	0.64
	Tia Juana	34.48	1.11
Brazil	Marlim	20.24	0.75
Colombia	Cano Limon	29.02	0.52
	Cupiagua	43.08	0.08
	Cusiana	39.39	0.17
Argentina	Neuquen Rio Negro	35.27	0.47
	San Sebastian	69.10	0.01
	Tierra Del Fuego	43.20	0.08

Source. BP Crude Assay Library reported by Haverly Systems

Annexure 4.5
Major crude oils from Russia

Region	Crude	API	Sulphur (wt%)
Russia	Barents Sea	46.71	0.02
	E4 (Gravenshon)	19.84	1.95
	E4 Heavy	18.00	2.35
	Kalingrad	40.96	0.12
	M100 (Atres ex Russia)	17.60	2.02
	M100 Heavy	16.67	2.09
	M100 Res	14.80	2.79
	Onako Light	48.40	0.15
	Onako Medium	38.51	1.15
	Romashkino	31.14	1.30
	Siberian Light	35.15	0.57
	Urals Light	32.18	1.50
	Urals Heavy	28.39	2.36
	Urals South	33.61	0.92
Kazakhastan	Kumkol	41.20	0.11
	Tengiz	46.60	0.55

Source BP Crude Assay Library reported by Haverly Systems

Annexure 4.6
Major crude oils from Asia and Far East

Region	Crude	API	Sulphur (wt%)
Indonesia	Arun Condensate	58.18	0.00
	Ardjuna	35.2	0.11
	Attaka	43.52	0.06
	Bekapai	41.20	0.08
	Badak	41.31	0.05
	Bima	21.10	0.25
	Bontang	50.85	0.03
	Cinta	33.40	0.08
	Duri	20.90	0.21
	Kakap	51.50	0.05
	Kerapu	45.15	0.02
	Lalang	38.06	0.05
	LSW Ex Pulau Sambu	30.31	0.13
	LSWR Ex Dumai	27.22	0.13
	Minas	34.46	0.08
	Mudi	36.50	0.44
	Pagerungan Condensate	61.28	0.00
	Sembilang	35.96	0.05
	Udang	37.76	0.04
	Widun	33.30	0.07
	Walio	36.25	0.57
Malaysia	Bintulu	35.96	0.06
	Bunga Kekwa	36.85	0.05
	Dulang	38.47	0.05
	Labuan	31.61	0.08
	Miri Light	32.37	0.08
	Tapis Blend	45.27	0.03
	Terengganu	47.39	0.03
Australia	Airlie Blend	43.73	0.02
	Cossack	46.82	0.04
	Jackson	45.38	0.03
	Saladin	48.41	0.02
	Skua	41.48	0.04
	Stag	18.39	0.11
	Surat	44.82	0.03
	Thvenard	37.56	0.04
	Wandoo	19.27	0.14
China	Liu Hua	22.82	0.19
	Lufeng	32.75	0.07
	Nanhai Export Blend	38.78	0.06
	Xi Xiang	32.18	0.09
Vietnam	Bach Ho	40.22	0.04
	Dai Hung	29.11	0.10
	Rang Dong	39.91	0.04
	Ruby	35.66	0.08

Source BP Crude Assay Library reported by Haverly Systems, reports of HPI Consultants, Inc.

Annexure 4.7
Crude oil classification

Crude	API	Sulphur	Example : Crude (Country of origin)
Heavy High Sulphur (Heavy sour)	< 30	> 1%	Arab Heavy (Saudi Arabia), Al Shaheen (Qatar), ANS (USA).
Heavy Medium-Sulphur (Heavy Medium)	< 30	Bet 0.5% to 1%	Marlim (Brazil), Cano Limon (Colombia), Kiame (Angola).
Heavy Low Sulphur (Heavy Sweet)	< 30	< 0.5%	Bonny Medium (Nigeria), Forcados Blend (Nigeria), Djeno (Cong
Light High Sulphur (Light Sour)	>= 30	> 1%	Seuz Blend (Egypt), Iranian Light (Iran), Kuwait (Kuwait).
Light Medium Sulphur (Light Medium)	> =30	Bet 0.5% to 1%	Flotta Mix (UK), Asab (UAE), Syrian Light (Syria).
Light Low Sulphur (Light Sweet)	> =30	< 0.5%	Bonny Light (Nigeria), Brass River (Nigeria), Attaka (Indonesia).

Source. Wang, Haijiang Henry, 1999. China's Oil Industry and Market, Amsterdam: Elsevier ; Haverly Library of Crude oils

Annexure 5.1
Crude-wise throughput by Indian refineries (2000-01P) (TMT)

	HPC	BPC	GUJ	RPL	KRL	CPCL	VIS	MRPL	CBU	MAT	PANI	BAR	HAL	GAU	DIG	BRPL	NRL	Total
Indigenous Crude																		
Bombay High	2165	5919	832		3180	1261			9	1555	90							15011
S Gujarat			2301															2301
N Gujarat			3371															3371
Nanmanam									434									434
KG Onshore									43									43
PY 3						182			39									221
Assam-Oil												402		397	679	856	1431	3765
Assam-ONGC												300		310		552	20	1182
Sub-Total	2165	5919	6504	0	3180	1443	0	0	525	1555	90	702	0	707	679	1408	1451	26328
PSC/JVC						0	2577											2577
Sub total-Indigenous	2165	5919	6504	0	3180	1443	2577	0	525	1555	90	702	0	707	679	1408	1451	28905
Imported																		
High Sulphur																		
Arab Mix (80 20)	2996	15	287		37	1958				275	175		1286					7029
Basra Light			118			491	60			132	121		523					1445
Dubai	16	592	164				363	398		55	104		39					1731
Iran Mix		152	150		1646	84		2382		167	123							4704
Kuwait		1578	1255		575		777			1443	1474		30					7132
Murban			12		118			85		32								247
Oman																		0
Suezmix		51	314		87		130			253	228							1063
UmmSaif						51												51
Upper Zakum	80		543			434	6			809	584		1413					3869
Zeit Bay					86													86
Arab Extra Light	318				123			83										524
Qatar Land						52												52
Lower Zakum		68																68
Masila					31		144	259										434
Others				25716	46	41		681										26484
Sub-Total	3410	2456	2843	25716	2749	3111	1480	3888	0	3166	2809	0	3291	0	0	0	0	54919
Low Sulphur																		
Es Sider			53							44	21							118
Badin										45								45
Bonny Light			832		819	118	966	134	0	762	890	598	169			82		5370
Brent Blend			56		40	276	472				26	693	101					1664
Escravos		163	1284		614	328	558	45		1162	1543	206						5903
Forcados			402				119			363	317	52						1253
Labuan						73		260	5			610	236					1184
Minlight		55				555		5	20				29					664
Palanca						2	10					15						27
Qua Iboe			31		47	140	72	127		37	12	162	19					647
Soyo Blend																		0
Others					27		29	1802	8			2						1868
Tapis								114	21			82	30					247
Cabinda					44		58											102
Nemba		71					60	63										194
Others							6											6
Sub-Total	0	289	2658	0	1591	1492	2350	2550	54	2413	2809	2420	584	0	0	82	0	19292
Sub-Total (Imported)	3410	2745	5501	25716	4340	4603	3830	6438	54	5579	5618	2420	3875	0	0	82	0	74211
Total (Ind+Imp)	5575	8664	12005	25716	7520	6046	6407	6438	579	7134	5708	3122	3875	707	679	1490	1451	103116

Source. OCC

Annexure 5.2
Sulphur content of petroleum products as per Xth plan
Motor Spirit

- MS produced in the country meets the sulphur content specification which has been reduced from 0.2% to 0.1% from 2000.
- In accordance with MOST Gazette notification, Euro II vehicular emission norms are in place in the National Capital Region (NCR) and Mumbai and Kolkata municipal area. MS with maximum sulphur content of 0.05% is supplied to these regions.
- MS with sulphur content of 0.05% is to be produced in the rest of the country in 4-5 years.
- Introduction of Euro III emission norms would require MS with a sulphur content of 0.015% to be supplied to the major cities in the next 4-5 years.

High Speed Diesel

In accordance with HSD specifications notified by MOE&F and MOST, the following milestones were achieved or are targeted to be achieved in the country:

- Supply of HSD with 0.5% sulphur (brought down from the earlier level of 0.1%) in the 4 metro cities and Taj trapezium with effect from April, 1996.
- Supply of HSD with 0.25% sulphur in the Taj trapezium with effect from September, 1996.
- Supply of HSD with 0.25% sulphur in inner Delhi with effect from August, 1997.
- Supply of HSD with 0.25% sulphur in entire Delhi, Mumbai, Kolkata and Chennai with effect from April, 1998.
- Supply of HSD with 0.25% sulphur in the entire country with effect from January, 2000.
- In accordance with Bharat stage II vehicular emission norms, HSD with ultra low sulphur content of 0.05% was introduced in NCR in April 2000 for non-commercial vehicles.
- From March, 2001, the entire HSD supplied to the National capital Territory is having sulphur content of 0.05%.
- HSD with sulphur content of 0.05% is being supplied to the Mumbai municipal limit since October 2000 and in the Kolkata municipal limit since January, 2001.
- Plan exists to supply HSD with 0.05% sulphur content in other metros and rest of the country by 2005.

Source. Xth Plan

Annexure 6.1
Charter hire rates for coastal movement of crude

Distances in miles

From/To	Cochin	Chennai	Haldia	Bombay	Kandla	Vizag	Vadinar
Cochin	NA	1752	3060	1170	1906	2280	-
Chennai	1752	NA	1550	2916	3648	656	-
Haldia	3060	1550	NA	4224	4956	884	-
Bombay	1170	2916	4224	NA	830	3444	748
Vizag	2280	656	884	3444	4176	-	-
Vadinar	-	-	-	748	-	-	NA

Speed	12	knots/hr.
	288	knots/day
	331.4246	Miles/day

Charter hire rates	$/Day	Rs/Day
LRII	15000	690000
LRI	14800	680800
MR	12500	575000

Freight rates LR II (Rs./MT)

From/To							
Cochin	NA	30.40	53.09	20.30	33.07	39.56	-
Chennai	30.40	NA	26.89	50.59	63.29	11.38	-
Haldia	53.09	26.89	NA	73.28	85.98	15.34	-
Bombay	20.30	50.59	73.28	NA	14.40	59.75	12.98
Vizag	39.56	11.38	15.34	59.75	72.45	-	-
Vadinar	-	-	-	12.98	-	-	NA

Freight rates LR I (Rs./MT)

From/To							
Cochin	NA	57.58	100.57	38.45	62.64	74.94	-
Chennai	57.58	NA	50.94	95.84	119.90	21.56	-
Haldia	100.57	50.94	NA	138.83	162.89	29.05	-
Bombay	38.45	95.84	138.83	NA	27.28	113.19	24.58
Vizag	74.94	21.56	29.05	113.19	137.25	-	-
Vadinar	-	-	-	24.58	-	-	NA

Freight rates MR (Rs./MT)

From/To							
Cochin	NA	86.85	151.68	58.00	94.48	113.02	-
Chennai	86.85	NA	76.83	144.54	180.83	32.52	-
Haldia	151.68	76.83	NA	209.38	245.67	43.82	-
Bombay	58.00	144.54	209.38	NA	41.14	170.72	37.08
Vizag	113.02	32.52	43.82	170.72	207.00	-	-
Vadinar	-	-	-	37.08	-	-	NA

Annexure 8.1
ONGC's investment commitments in comparison to exploration investment commitments of other oil majors

ONGC's investment commitments*		
ONGC's investment commitments for IOR and EOR schemes	Rs. Million	47950.1
incremental oil production in next 20 years	MMT	61.53
Investment commitment	$/bbl	2.31

Exploration commitments of world oil majors in Asia-Pacific region for 2000-01#

	Exploration ($ million)	Extensions and discovenes (Million barrels)	Investment ($/bbl)
Exxon Mobil Corporation	145.0	39	3.7
TotalFinaElf	31.4	1	31.4
Unocal Corporation	134.0	30	4.5
Apache Corporation	40.9	6.1	6.7
Benton Oil and Gas Company	4.3	12.6	0.3
Broken Hill Propriety Company Ltd.	21.9	19.9	1.1
CNOOC Limited	73.7	76	1.0
Fletcher Challenge Energy	11.6	6	1.9
Gulf Canada Resources Limited	27.6	1	27.6
Magellan Petroleum Company	2.0		
New field Exploration Company	9.1		
Nexen Inc.	12.8		
Noble Affiliates, Inc.			
PetroChina Company Limited	1311.4	297	4.4
Pogo Producing Company	11.0	5.6	2.0
Repsol YPF, S.A.	13.8	7.6	1.8
Sinopec Corp.	392.4	133	3.0
Swift Energy Company	1.6	11.2	0.1
Talisman Energy Inc.	20.3	4.1	5.0
Tipperary Corporation	0.4		
Total	2265.1	650	3.5

* ONGC's Annual Report 2000-01

Global E & P Trends 2001, Andersen Consulting

Annexure 9.1
Evaluation of options for BPCL Mumbai

Element	Unit	Factors	Option A	Option B	Option C	Option D
Bonny Light - Escravos fob (Januray 2002)	$/bbl		19.60	19.60	19.60	19.60
Bonny Light - Escravos fob (Januray 2002)	Rs/MT	46	6607.04	6607.04	6607.04	6607.04
Freight VLCC	$/MT				15.27	15.27
Freight VLCC	Rs/MT				702.29	702.29
Fob + freight	Rs/MT				7309.33	7309.33
Insurance	Rs/MT	0.347%			25.36	25.36
Ocean Loss	Rs/MT	0.2%			14.62	14.62
Cif	Rs/MT				7349.31	7349.31
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transhipment	Rs/MT					
Mooring	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				7433.56	7433.56
LC Charges	Rs/MT	0.3%			22.05	22.05
Basic Customs duty	Rs/MT	10%			743.36	743.36
Cost inluding duty	Rs/MT				8114.72	8114.72
Inland freight	Rs/MT		0.00	0.00	0.00	0.00
Price received by ONGC	Rs/MT		6607.04	6607.04	8198.96	8198.96
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	264.28			327.96
Total payment by ONGC	Rs/MT		2914	2650	2650	2978
ONGC realisation	Rs/MT		3692.76	3957.04	5548.96	5221.00
ONGC realisation	$/bbl		10.95	11.74	16.46	15.48
Premium (+)/discount (-)	$/bbl		0.916	0.916	0.916	0.916
ONGC cost of production	$/bbl		9	9	9	9
ONGC surplus	$/bbl		2.87	3.65	8.37	7.40
Corporate Tax (at 35%)	$/bbl		1.00	1.28	2.93	2.59
ONGC net surplus	$/bbl		1.86	2.37	5.44	4.81

Annexure 9.2
Evaluation of options for HPCL Mumbai

Element	Unit	Factors	Option A	Option B	Option C	Option D
Bonny Light - - Escravos fob (Januray 2002)	$/bbl		19.60	19.60	19.60	19.60
Bonny Light - Escravos fob (Januray 2002)	Rs/MT	46	6607.04	6607.04	6607.04	6607.04
Freight VLCC	$/MT				15.27	15.27
Freight VLCC	Rs/MT				702.29	702.29
Fob + freight	Rs/MT				7309.33	7309.33
Insurance	Rs/MT	0.347%			25.36	25.36
Ocean Loss	Rs/MT	0.2%			14.62	14.62
Cif	Rs/MT				7349.31	7349.31
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transhipment	Rs/MT					
Mooring	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				7433.56	7433.56
LC Charges	Rs/MT	0.3%			22.05	22.05
Basic Customs duty	Rs/MT	10%			743.36	743.36
Cost inluding duty	Rs/MT				8114.72	8114.72
Inland freight	Rs/MT		0.00	0.00	0.00	0.00
Price received by ONGC	Rs/MT		6607.04	6607.04	8198.96	8198.96
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	264.28			327.96
Total payment by ONGC	Rs/MT		2914	2650	2650	2978
ONGC realisation	Rs/MT		3692.76	3957.04	5548.96	5221.00
ONGC realisation	$/bbl		10.95	11.74	16.46	15.48
Premium (+)/discount (-)	$/bbl		0.907	0.907	0.907	0.907
ONGC cost of production	$/bbl		9	9	9	9
ONGC surplus	$/bbl		2.86	3.64	8.36	7.39
Corporate Tax (at 35%)	$/bbl		1.00	1.27	2.93	2.59
ONGC net surplus	$/bbl		1.86	2.37	5.44	4.80

Annexure 9.3
Evaluation of options for IOC Koyali

Element	Unit	Factors	Option A	Option B	Option C	Option D
Bonny Light: Escravos - fob (Jan '02)	$/bbl		19.60	19.60	19.60	19.60
Bonny Light: Escravos - fob (Jan '02)	Rs/MT	46	6607.04	6607.04	6607.04	6607.04
Freight VLCC	$/MT				15.27	15.27
Freight VLCC	Rs/MT				702.29	702.29
Fob + freight	Rs/MT				7309.33	7309.33
Insurance	Rs/MT	0.347%			25.36	25.36
Ocean Loss	Rs/MT	0.2%			14.62	14.62
Cif	Rs/MT				7349.31	7349.31
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transhipment	Rs/MT					
Mooring	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				7433.56	7433.56
LC Charges	Rs/MT	0.3%			22.05	22.05
Basic Customs duty	Rs/MT	10%			743.36	743.36
Cost inluding duty	Rs/MT				8114.72	8114.72
Inland freight (vadinar-refinery)	Rs/MT		0.00	0.00	0.00	0.00
Price received by ONGC	Rs/MT		6607.04	6607.04	8198.96	8198.96
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	264.28			327.96
Total payment by ONGC	Rs/MT		2914	2650	2650	2978
ONGC realisation	Rs/MT		3692.76	3957.04	5548.96	5221.00
ONGC realisation	$/bbl		10.95	11.74	16.46	15.48
Premium (+)/discount (-)	$/bbl		0.2	0.2	0.2	0.2
ONGC cost of production	$/bbl		9	9	9	9
ONGC surplus	$/bbl		2.15	2.94	7.66	6.68
Corporate Tax (at 35%)	$/bbl		0.75	1.03	2.68	2.34
ONGC net surplus	$/bbl		1.40	1.91	4.98	4.34

Annexure 9.4
Evaluation of options for IOC Mathura

Element	Unit	Factors	Option A	Option B	Option C	Option D
Bonny Light:Escravos - fob (Jan '02)	$/bbl		19.60	19.60	19.60	19.60
Bonny Light:Escravos - fob (Jan '02)	Rs/MT	46	6607.04	6607.04	6607.04	6607.04
Freight VLCC	$/MT				15.27	15.27
Freight VLCC	Rs/MT				702.29	702.29
Fob + freight	Rs/MT				7309.33	7309.33
Insurance	Rs/MT	0.347%			25.36	25.36
Ocean Loss	Rs/MT	0.2%			14.62	14.62
Cif	Rs/MT				7349.31	7349.31
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transhipment	Rs/MT					
Mooring	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				7433.56	7433.56
LC Charges	Rs/MT	0.3%			22.05	22.05
Basic Customs duty	Rs/MT	10%			743.36	743.36
Cost inluding duty	Rs/MT				8114.72	8114.72
Inland freight (vadinar-refinery)	Rs/MT		0.00	0.00	0.00	0.00
Price received by ONGC	Rs/MT		6607.04	6607.04	8198.96	8198.96
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	264.28			327.96
Total payment by ONGC	Rs/MT		2914	2650	2650	2978
ONGC realisation	Rs/MT		3692.76	3957.04	5548.96	5221.00
ONGC realisation	$/bbl		10.95	11.74	16.46	15.48
Premium (+)/discount (-)	$/bbl		0.207	0.207	0.207	0.207
ONGC cost of production	$/bbl		9	9	9	9
ONGC surplus	$/bbl		2.16	2.94	7.66	6.69
Corporate Tax (at 35%)	$/bbl		0.76	1.03	2.68	2.34
ONGC net surplus	$/bbl		1.40	1.91	4.98	4.35

Annexure 9.5
Evaluation of option for IOC Panipat

Element	Unit	Factors	Option A	Option B	Option C	Option D
Bonny Light:Escravos - fob (Jan '02)	$/bbl		19.60	19.60	19.60	19.60
Bonny Light:Escravos - fob (Jan '02)	Rs/MT	46	6607.04	6607.04	6607.04	6607.04
Freight VLCC	$/MT				15.27	15.27
Freight VLCC	Rs/MT				702.29	702.29
Fob + freight	Rs/MT				7309.33	7309.33
Insurance	Rs/MT	0.347%			25.36	25.36
Ocean Loss	Rs/MT	0.2%			14.62	14.62
Cif	Rs/MT				7349.31	7349.31
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transhipment	Rs/MT					
Mooring	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				7433.56	7433.56
LC Charges	Rs/MT	0.3%			22.05	22.05
Basic Customs duty	Rs/MT	10%			743.36	743.36
Cost inluding duty	Rs/MT				8114.72	8114.72
Inland freight (vadinar-refinery)	Rs/MT		0.00	0.00	0.00	0.00
Price received by ONGC	Rs/MT		6607.04	6607.04	8198.96	8198.96
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	264.28			327.96
Total payment by ONGC	Rs/MT		2914	2650	2650	2978
ONGC realisation	Rs/MT		3692.76	3957.04	5548.96	5221.00
ONGC realisation	$/bbl		10.95	11.74	16.46	15.48
Premium (+)/discount (-)	$/bbl		0.22	0.22	0.22	0.22
ONGC cost of production	$/bbl		9	9	9	9
ONGC surplus	$/bbl		2.17	2.96	7.68	6.70
Corporate Tax (at 35%)	$/bbl		0.76	1.03	2.69	2.35
ONGC net surplus	$/bbl		1.41	1.92	4.99	4.36

Annexure 9.6
Evaluation of options for Kochi refinery

Element	Unit	Factors	Option A	Option B	Option C	Option D
Bonny Light:Escravos - fob (Jan '02)	$/bbl		19.60	19.60	19.60	19.60
Bonny Light:Escravos - fob (Jan '02)	Rs/MT	46	6607.04	6607.04	6607.04	6607.04
Freight VLCC	$/MT				15.27	15.27
Freight VLCC	Rs/MT				702.29	702.29
Fob + freight	Rs/MT				7309.33	7309.33
Insurance	Rs/MT	0.347%			25.36	25.36
Ocean Loss	Rs/MT	0.2%			14.62	14.62
Cif	Rs/MT				7349.31	7349.31
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transhipment	Rs/MT					
Mooring	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				7433.56	7433.56
LC Charges	Rs/MT	0.3%			22.05	22.05
Basic Customs duty	Rs/MT	10%			743.36	743.36
Cost inluding duty	Rs/MT				8114.72	8114.72
Inland freight	Rs/MT		0.00	0.00	0.00	0.00
Price received by ONGC	Rs/MT		6607.04	6607.04	8198.96	8198.96
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	264.28			327.96
Total payment by ONGC	Rs/MT		2914	2650	2650	2978
ONGC realisation	Rs/MT		3692.76	3957.04	5548.96	5221.00
ONGC realisation	$/bbl		10.95	11.74	16.46	15.48
Premium (+)/discount (-)	$/bbl		0.893	0.893	0.893	0.893
ONGC cost of production	$/bbl		9	9	9	9
ONGC surplus	$/bbl		2.84	3.63	8.35	7.38
Corporate Tax (at 35%)	$/bbl		1.00	1.27	2.92	2.58
ONGC net surplus	$/bbl		1.85	2.36	5.43	4.80

Annexure 9.7
Evaluation of options for HPCL Vizag

Element	Unit	Factors	Option A	Option B	Option C	Option D
Bonny Light:Escravos – fob (Jan '02)	$/bbl		19.60	19.60	19.60	19.60
Bonny Light:Escravos – fob (Jan '02)	Rs/MT	46	6607.04	6607.04	6607.04	6607.04
Freight VLCC	$/MT				15.27	15.27
Freight VLCC	Rs/MT				702.29	702.29
Fob + freight	Rs/MT				7309.33	7309.33
Insurance	Rs/MT	0.347%			25.36	25.36
Ocean Loss	Rs/MT	0.2%			14.62	14.62
Cif	Rs/MT				7349.31	7349.31
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transhipment	Rs/MT					
Mooring	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				7433.56	7433.56
LC Charges	Rs/MT	0.3%			22.05	22.05
Basic Customs duty	Rs/MT	10%			743.36	743.36
Cost inluding duty	Rs/MT				8114.72	8114.72
Inland freight	Rs/MT		0.00	0.00	0.00	0.00
Price received by ONGC	Rs/MT		6607.04	6607.04	8198.96	8198.96
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	264.28			327.96
Total payment by ONGC	Rs/MT		2914	2650	2650	2978
ONGC realisation	Rs/MT		3692.76	3957.04	5548.96	5221.00
ONGC realisation	$/bbl		10.95	11.74	16.46	15.48
Premium (+)/discount (-)	$/bbl		0.933	0.933	0.933	0.933
ONGC cost of production	$/bbl		9	9	9	9
ONGC surplus	$/bbl		2.88	3.67	8.39	7.42
Corporate Tax (at 35%)	$/bbl		1.01	1.28	2.94	2.60
ONGC net surplus	$/bbl		1.88	2.38	5.45	4.82

Annexure 9.8
Evaluation of options for MRPL

Element	Unit	Factors	Option A	Option B	Option C	Option D
Bonny Light:Escravos - fob (Jan '02)	$/bbl		19.60	19.60	19.60	19.60
Bonny Light:Escravos - fob (Jan '02)	Rs/MT	46	6607.04	6607.04	6607.04	6607.04
Freight VLCC	$/MT				15.27	15.27
Freight VLCC	Rs/MT				702.29	702.29
Fob + freight	Rs/MT				7309.33	7309.33
Insurance	Rs/MT	0.347%			25.36	25.36
Ocean Loss	Rs/MT	0.2%			14.62	14.62
Cif	Rs/MT				7349.31	7349.31
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transhipment	Rs/MT					
Mooring	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				7433.56	7433.56
LC Charges	Rs/MT	0.3%			22.05	22.05
Basic Customs duty	Rs/MT	10%			743.36	743.36
Cost inluding duty	Rs/MT				8114.72	8114.72
Inland freight	Rs/MT		0.00	0.00	0.00	0.00
Price received by ONGC	Rs/MT		6607.04	6607.04	8198.96	8198.96
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	264.28			327.96
Total payment by ONGC	Rs/MT		2914	2650	2650	2978
ONGC realisation	Rs/MT		3692.76	3957.04	5548.96	5221.00
ONGC realisation	$/bbl		10.95	11.74	16.46	15.48
Premium (+)/discount (-)	$/bbl		0.912	0.912	0.912	0.912
ONGC cost of production	$/bbl		9	9	9	9
ONGC surplus	$/bbl		2.86	3.65	8.37	7.40
Corporate Tax (at 35%)	$/bbl		1.00	1.28	2.93	2.59
ONGC net surplus	$/bbl		1.86	2.37	5.44	4.81

Annexure 9.9
Evaluation of options for CPCL Chennai

Element	Unit	Factors	Option A	Option B	Option C	Option D
Bonny Light:Escravos – fob (Jan '02)	$/bbl		19.60	19.60	19.60	19.60
Bonny Light:Escravos – fob (Jan '02)	Rs/MT	46	6607.04	6607.04	6607.04	6607.04
Freight VLCC	$/MT				15.27	15.27
Freight VLCC	Rs/MT				702.29	702.29
Fob + freight	Rs/MT				7309.33	7309.33
Insurance	Rs/MT	0.347%			25.36	25.36
Ocean Loss	Rs/MT	0.2%			14.62	14.62
Cif	Rs/MT				7349.31	7349.31
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transhipment	Rs/MT					
Mooring	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				7433.56	7433.56
LC Charges	Rs/MT	0.3%			22.05	22.05
Basic Customs duty	Rs/MT	10%			743.36	743.36
Cost inluding duty	Rs/MT				8114.72	8114.72
Inland freight	Rs/MT		0.00	0.00	0.00	0.00
Price received by ONGC	Rs/MT		6607.04	6607.04	8198.96	8198.96
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	264.28			327.96
Total payment by ONGC	Rs/MT		2914	2650	2650	2978
ONGC realisation	Rs/MT		3692.76	3957.04	5548.96	5221.00
ONGC realisation	$/bbl		10.95	11.74	16.46	15.48
Premium (+)/discount (-)	$/bbl		0.933	0.933	0.933	0.933
ONGC cost of production	$/bbl		9	9	9	9
ONGC surplus	$/bbl		2.88	3.67	8.39	7.42
Corporate Tax (at 35%)	$/bbl		1.01	1.28	2.94	2.60
ONGC net surplus	$/bbl		1.88	2.38	5.45	4.82

Annexure 9.10
Disruption in crude supplies

Date of disruption	Duration in months	Average gross size of shortfall (mb/d)	Reason
11/56 - 3/57	4	2	Suez War
12/66 - 3/67	3	0.7	Syrian transit fee dispute
6/67 - 8/67	2	2	Six day war
5/70 - 1/71	9	1.3	Libyan price controversy
4/71 - 8/71	5	0.6	Algerian nationalisation
3/73 - 5/73	2	0.5	Unrest in lebanon, damage in transit facilities
10/73 - 3/74	6	2.6	Arab-Israeli war
4/76 - 5/76	2	0.3	Civil war in lebanon
May-77	1	0.7	Damage to saudi arab field
11/78 - 4/79	6	3.5	Iranian revolution
10/80 - 12/80	3	3.3	Iran-Iraq war
8/90 - 10/90	3	4.6	Gulf war
Overall Average	3.83	1.84	
Average (1978/79-90)	4	3.8	

Source. Energy Information Administration (USA)

Annexure 9.11
Increase in fixed cost for the refineries

	Unit	HPC	BPC	GUJ	RPL	KRL	CPCL	VIS	MRPL	CBU	MAT	PANI
Total throughput	'000 tonnes	5575	8664	12005	25716	7520	6046	6407	6438	579	7134	5708
Imported	'000 tonnes	3410	2745	5501	25716	4340	4603	2350	6438	54	5579	5618
Share of ONGC crudes	'000 tonnes	2165	5919	832	0	3180	1261	0	0	9	1555	90
Replacement imported	'000 tonnes	2165	5919	832	0	3180	1261	0	0	9	1555	90
Share in total imported	%	6	10	7	29	9	7	3	7	0	8	7
Disruption	'000 tonnes	139	216	158	641	187	146	59	160	2	178	142
Old throughput	'000 tonnes	5575	8664	12005	25716	7520	6046	6407	6438	579	7134	5708
New Throughput	'000 tonnes	5436	8448	11847	25075	7333	5900	6348	6278	577	6956	5566
Old Fixed costs	Rs/MT	127	229	182	106	403	382	95	382	37	149	369
OldFixed costs	Rs Million	708	1980	2185	2714	3033	2310	609	2459	21	1063	2106
New Fixed costs	Rs/MT	130	234	184	108	414	392	96	392	37	153	378
Increase in fixed costs	Rs/MT	3	6	2	3	10	9	1	10	0	4	9
Increase in fixed costs	$/bbl	0.010	0.017	0.007	0.008	0.031	0.028	0.003	0.029	0.000	0.011	0.028

Annexure 9.12
Demurrage Expenses

West Coast India						
Supplier	**Quantity (mbl)**	**Load port**	**Lay Can**	**Indian coast/port**	**Freight Rate**	**Demurrage ($)**
Chevron	1.9	Escravos	6/7 Oct.	WCI	2.675	42500
Chevron	1.9	Escravos	16/17 Oct	WCI	3.275	68000
Vitol	1.84	Escravos	21-Oct	WCI	3.7	68000
Vitol	1.84	Escravos	1/2 Nov	WCI	3.5	60000
Chevron	1.9	Escravos	11/12 Nov	WCI	3.5	60000
Glencore	1.84	Escravos	16/17 Nov.	WCI	3.2	48750
Vitol	1.84	Escravos	23/24 Dec	WCI	3.675	55000
Glencore	1.84	Escravos	15/17 Dec	WCI	3.7	52500
Chevron	1.9	Escravos	18/19 Dec	WCI	4.125	68000
Glencore	1.84	Escravos	23/24 Jan	WCI	3.5	55000
Chevron	1.9	Escravos	10/11 Jan	WCI	3.55	50000
NNPC	1.85	Qua Iboe + Bonny	15/16 Jan	WCI	4	67500
Glencore	1.84	Escravos	7/8 Feb	WCI	3	48750
Shell	2	Bonny	10/11 Jan	WCI	3.25	59000
NNPC	1.85	Qua Iboe + Bonny	15/16 Jan	WCI	3.305	59000
Shell	2	Bonny	22/23 Mar	Vadinar	2.7	52500
Shell	2	Bonny	11/12 Apr	Vadinar	2.5	40000
Vitol	1.84	Escravos	23/24 Apr	Vadinar	2.5	38000
NNPC	1.9	Escravos	16/17 Apr	LPO WCI	2.5	40000
Total demurrage		$				1032500
Total quantity		million barrels				35.82
Total quantity		million tonnes				4.89
Average demurrage		Rs/T				9.72

East Coast India						
Supplier	Quantity (mbl)	Load port	Lay Can	Indian coast/port	Freight Rate	Demurrage ($)
Shell	2.00	Bonny	6/7 Nov	ECI	4.1	62000
Vitol	1.9	Escravos	24/25 Nov.	ECI	3.7	55000
Vitol	1.9	Escravos	01/2 Dec.	ECI	3.5	48750
NNPC	1.87	Qua Iboe+ Bonny	10/11 Nov	ECI	4.215	48750
NNPC	1.9	Qua Iboe	10/11 Dec	ECI	3.5	55000
Shell	2	Bonny	16/17 Dec.	ECI	3.5	48750
Vitol	1.9	Escravos	6/7 Jan	ECI	3.475	50000
Shell	2	Bonny	7/8 Jan	ECI	3.825	62500
Glencore	910 kbl	Bonny	10/11 Mar	Sand Heads	1.98	32000
Total demurrage		$				462750
Total quantity		Million barrels				16.38
Total quantity		Million tonnes				2.23
Average demurrage		Rs/T				9.53

Annexure 9.13
Annutised cost of desalting the BH crude

Head	Unit	Value
Capital Cost	Rs Million	1500.00
Phasing of investment		
Year-2		0
Year-1		0.5
Year-0		0.5
Total		1
Discount factor		0.12
NPV factor		1.12
Capital cost (incld IDC)	Rs.million	1683
Life of plant	Years	15
Capital Recovery Factor		0.15
Annutised capital cost	Rs.million	247
Annutised capital cost	Rs/MT	16.471

Annexure 10.1
Evaluation of options for Koyali refinery

Element	Unit	Factors	Option A	Option B	Option C
Bonny Light - fob (Jan '02)	$/bbl		19.63	19.63	19.63
Bonny Light - fob (Jan '02)	Rs/MT	46	6618.84	6618.84	6618.84
Freight VLCC	$/MT				15.43
Freight VLCC	Rs/MT				709.82
Fob + freight	Rs/MT				7328.66
Insurance	Rs/MT	0.347%			25.43
Ocean Loss	Rs/MT	0.2%			14.66
Cif	Rs/MT				7368.75
Port dues	Rs/MT	11.04			11.04
Berth Hire	Rs/MT				
Pilotage	Rs/MT	24.794			24.79
Garbage charges	Rs/MT	0.01			0.01
Pier Dues	Rs/MT	18.4			18.40
Pumping facilities	Rs/MT				
Transhipment	Rs/MT				
Mooring	Rs/MT				
Stream Dues	Rs/MT				
Wharfage	Rs/MT	30			30.00
Landing charges	Rs/MT				84.24
CIF + Landing charges	Rs/MT				7452.99
LC Charges	Rs/MT	0.3%			22.11
Basic Customs duty	Rs/MT	10%			745.30
Cost inluding duty	Rs/MT				8136.15
Inland freight (vadinar-refinery)	Rs/MT		0.00	0.00	0.00
Price received by ONGC	Rs/MT		6618.84	6618.84	8220.40
Cess	Rs/MT		1800	1800	1800
Royalty	Rs/MT		850	850	850
Central sales tax	Rs/MT	4%	264.75		
Total payment by ONGC	Rs/MT		2915	2650	2650
ONGC realisation	Rs/MT		3704.09	3968.84	5570.40
ONGC realisation	$/bbl		10.99	11.77	16.52
Premium (+)/discount (-)	$/bbl		-1.112	-1.112	-1.112
ONGC cost of production	$/bbl		9	9	9
ONGC surplus	$/bbl		0.87	1.66	6.41
Corporate Tax (at 35%)	$/bbl		0.31	0.58	2.24
ONGC net surplus	$/bbl		0.57	1.08	4.17

Annexure 10.2
Calculations for increase in fixed costs

	Unit	NG	SG
Total throughput	000 tonnes	12005	12005
Imported	000 tonnes	5501	5501
Share of ONGC crudes	000 tonnes	3371	2301
Replacement imported	000 tonnes	3371	2301
Total imports	000 tonnes	8872	7802
Share in total imported	%	11.43	10.19
Share in disruption	Million tonnes	0.25	0.22
Old throughput	Million tonnes	12.005	12.005
New Throughput	Million tonnes	11.755	11.782
Old Fixed costs	Rs/MT	182	182
OldFixed costs	Rs Million	2185	2185
New Fixed costs	Rs/MT	186	185
Increase in fixed costs	Rs/MT	4	3
Increase in fixed costs	$/bbl	0.011	0.010

Annexure 10.3
Calculation of pipeline costs

Heads	Unit	Value
Length of pipeline from Salaya - Koyali	Km	414
Pipeline cost	Rs million/inch dia/km	0.1
Diameter	Inch	16
Total pipeline cost	Rs million	745.2

Calculation of annutised capital cost

Heads	Unit	Value
Capital Cost	Rs Million	745
Phasing of investment		
Year-2		0
Year-1		0
Year-0		1
Total		1
Discount factor		0.12
NPV factor		1.06
Capital cost (incld IDC)	Rs.million	789
Life of pipeline	Years	30
Capital Recovery Factor		0.12
Annutised capital cost	Rs.million	98
Annutised capital cost	Rs/t	17.17

Annexure 10.4
Calculation of annutised capital cost for the desalter plant

Heads	Unit	Value
Capital Cost	Rs Million	300
Phasing of investment		
Year -2		0.3
Year -1		0.2
Year -0		0.5
Total		1
Discount factor		0.12
NPV factor		1.16
Capital cost (incld IDC)	Rs.million	349
Life of pipeline	Years	15
Capital Recovery Factor		0.15
Annutised capital cost	Rs.million	51
Annutised capital cost	**Rs/t**	**22.30**

Annexure 11.1
Evaluation of options for CBU

Element	Unit	Factors	Option A	Option B	Option C
Arab Light - fob (Jan '02)	$/bbl		18.81	18.81	18.81
Arab Light - fob (Jan '02)	Rs/MT	46	6342.36	6342.36	6342.36
Freight VLCC	$/MT				6.38
Freight VLCC	Rs/MT				293.61
Fob + freight	Rs/MT				6635.96
Insurance	Rs/MT	0.347%			23.03
Ocean Loss	Rs/MT	0.2%			13.27
Cif	Rs/MT				6672.26
Port dues	Rs/MT	11.04			11.04
Berth Hire	Rs/MT				
Pilotage	Rs/MT	24.794			24.79
Garbage charges	Rs/MT	0.01			0.01
Pier Dues	Rs/MT	18.4			18.40
Pumping facilities	Rs/MT				
Transhipment	Rs/MT				
Mooring	Rs/MT				
Stream Dues	Rs/MT				
Wharfage	Rs/MT	30			30.00
Landing charges	Rs/MT				84.24
CIF + Landing charges	Rs/MT				6756.50
LC Charges	Rs/MT	0.3%			20.02
Basic Customs duty	Rs/MT	10%			675.65
Cost inluding duty	Rs/MT				7367.93
Inland freight	Rs/MT		0.00	0.00	0.00
Price received by ONGC	Rs/MT		6342.36	6342.36	7452.17
Cess	Rs/MT		1800	1800	1800
Royalty	Rs/MT		850	850	850
Central sales tax	Rs/MT	4%	253.69		
Total payment by ONGC	Rs/MT		2904	2650	2650
ONGC realisation	Rs/MT		3438.66	3692.36	4802.17
ONGC realisation	$/bbl		10.20	10.95	14.24
Premium (+)/discount (-)	$/bbl		1.083	1.083	1.083
ONGC cost of production	$/bbl		9	9	9
ONGC surplus	$/bbl		2.28	3.03	6.33
Corporate Tax (at 35%)	$/bbl		0.80	1.06	2.21
ONGC net surplus	$/bbl		1.48	1.97	4.11

Annexure 11.2
Calculation for increase in fixed cost

	Unit	CBU
Total throughput	000 tonnes	579
Imported	000 tonnes	54
Share of ONGC crudes	000 tonnes	434
Replacement imported	000 tonnes	434
Total imports	000 tonnes	488
Share in total imported	%	0.65
Share in disruption	Million tonnes	0.014
Old throughput	Million tonnes	0.579
New Throughput	Million tonnes	0.565
Old Fixed costs	Rs/MT	36.58
OldFixed costs	Rs Million	21.18
New Fixed costs	Rs/MT	37.50
Increase in fixed costs	Rs/MT	0.920
Increase in fixed costs	$/bbl	0.003

Annexure 12.1
Evaluation of options for KG crude

Element	Unit	Factors	Option A	Option B	Option C	Option D
Arab Light - fob (Jan '02)	$/bbl		18.81	18.81	18.81	18.81
Arab Light - fob (Jan '02)	Rs/MT	46	6342.36	6342.36	6342.36	6342.36
Freight VLCC	$/MT				6.87	6.87
Freight VLCC	Rs/MT				316.19	316.19
Fob + freight	Rs/MT				6658.55	6658.55
Insurance	Rs/MT	0.347%			23.11	23.11
Ocean Loss	Rs/MT	0.2%			13.32	13.32
Cif	Rs/MT				6694.97	6694.97
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transhipment	Rs/MT					
Mooring	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				6779.21	6779.21
LC Charges	Rs/MT	0.3%			20.08	20.08
Basic Customs duty	Rs/MT	10%			677.92	677.92
Cost inluding duty	Rs/MT				7392.98	7392.98
Inland freight	Rs/MT		0.00	0.00	0.00	0.00
Price received by ONGC	Rs/MT		6342.36	6342.36	7477.22	7477.22
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	253.69			299.09
Total payment by ONGC	Rs/MT		2904	2650	2650	2949
ONGC realisation	Rs/MT		3438.66	3692.36	4827.22	4528.13
ONGC realisation	$/bbl		10.20	10.95	14.32	13.43
Premium (+)/Discount (-)	$/bbl		-0.046	-0.046	-0.046	-0.046
ONGC cost of production	$/bbl		9	9	9	9
ONGC surplus	$/bbl		1.15	1.90	5.27	4.38
Corporate tax (35%)	$/bbl		0.40	0.67	1.84	1.53
ONGC net surplus	$/bbl		0.75	1.24	3.43	2.85

Annexure 12.2
Annutised capital cost of desalter plant

Elements	Unit	Value
Capital Cost	Rs Million	30.00
Phasing of investment		
Year -2		0
Year -1		0
Year -0		1
Total		1
Discount factor		0.12
NPV factor		1.06
Capital cost (incld IDC)	Rs.million	31.75
Life of pipeline	Years	15
Capital Recovery Factor		0.15
Annutised capital cost	Rs.million	4.662
Annutised capital cost	Rs/t	15.53

Annexure 13.1
Evaluation of options for North East crudes

Element	Unit	Factors	Option A	Option B	Option C	Option D
Bonny Light - fob (Jan '02)	$/bbl		19.63	19.63	19.63	19.63
Bonny Light - fob (Jan '02)	Rs/MT	46	6618.84	6618.84	6618.84	6618.84
Freight VLCC	$/MT				16.60	16.60
Freight VLCC	Rs/MT				763.59	763.59
Fob + freight	Rs/MT				7382.43	7382.43
Insurance	Rs/MT	0.347%			25.62	25.62
Ocean Loss	Rs/MT	0.2%			14.76	14.76
Cif	Rs/MT				7422.82	7422.82
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transhipment	Rs/MT					
Mooring	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				7507.06	7507.06
LC Charges	Rs/MT	0.3%			22.27	22.27
Basic Customs duty	Rs/MT	10%			750.71	750.71
Cost inluding duty	Rs/MT				8195.79	8195.79
Inland freight (Haldia-refinery)	Rs/MT					
Price received by ONGC	Rs/MT		6618.84	6618.84	8280.03	8280.03
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	264.75			331.20
Total payment by ONGC	Rs/MT		2915	2650	2650	2981
ONGC realisation	Rs/MT		3704.09	3968.84	5630.03	5298.83
ONGC realisation	$/bbl		10.99	11.77	16.70	15.72
Premium (+)/discount (-)	$/bbl		-0.048	-0.048	-0.048	-0.048
ONGC cost of production	$/bbl		9	9	9	9
ONGC surplus	$/bbl		1.94	2.72	7.65	6.67
Corporate Tax (at 35%)	$/bbl		0.68	0.95	2.68	2.33
ONGC net surplus	$/bbl		1.26	1.77	4.97	4.33

Annexure 13.2
Annutised cost of desalting North Eastern crude

Element	Unit	Value
Capital Cost	Rs Million	201.30
Phasing of investment		
Year -2		0
Year -1		0.5
Year -0		0.5
Total		1
Discount factor		0.12
NPV factor		1.12
Capital cost (incld IDC)	Rs.million	225.82
Life of pipeline	Years	15
Capital Recovery Factor		0.15
Annutised capital cost	Rs.million	33.156
Annutised capital cost	Rs/t	16.470722

Annexures
Part-2
Natural Gas

Annexure 14.1
Overview of the Indian gas industry

Oil and gas were discovered in India in 1886 in Upper Assam. The Naharkatyia oilfield in Assam was the first oil and gas discovery of independent India in 1953, followed by the Moran field in 1956. Commercial utilization of natural gas in India started in the early sixties in Assam but really picked up after the development of the giant Bombay high field in the early eighties. Subsequently, South Bassein, another very large gas field was discovered in 1978 in the western offshore basin and brought into production around 1990.

The early focus was on oil production and as a result large amount of associated gas from producing oil fields was flared due to a lack of infrastructure and markets. Free gas finds were shut in for the same reason.

It was only in the early 1980's that the western offshore gas began to be exploited as a resource rather than being treated as a by-product. The government appointed a number of committees and expert groups to examine the ways in which the gas could be best utilised. The view that emerged was that the optimal use of gas would be in producing fertilisers. Initially there was quite some opposition to the use of gas for power generation but later the idea was accepted. In 1986 work began on the Hazira-Bijaipur-Jagdishpur (HBJ) gas transmission line linking the western offshore gas fields with fertiliser and power plants (Map 14.1.1). This resulted in a significant growth in gas production and use through the late 1980's. Flaring from the western offshore has diminished substantially in recent years and is now limited to only technical flaring. While the bulk of the western offshore gas is brought to Hazira, a part of it is taken to Uran in Maharashtra for use by power plants, urea plants and industries around Mumbai.

In the north-east, gas is produced in Assam, Arunachal Pradesh and Tripura. Associated gas has been produced in Assam for over 20 years but flaring has remained at high levels till recently. Free gas fields in Tripura are being used mainly for power generation. Some associated gas is being produced in Arunachal Pradesh but utilisation by a proposed gas-to-liquid plant is yet to start. Consequently, this gas has to be flared.

Next to Gujarat and the north-east, Andhra Pradesh has the largest gas reserves. Gas from ONGC's onshore fields and the offshore Ravva field is being used in producing urea, power generation and in industry. ONGC has made a number of discoveries in the area recently and gas has been allocated by the government for new power plants with a proposed capacity of 1800 MW. Cairns

Energy has recently announced a discovery in an offshore field named Annapurna from where they expect a peak production of around 5 MMCMD. There is an expectation of more gas finds in the area as exploration proceeds in the NELP blocks. Rajasthan and Tamil Nadu also use gas in small quantities.

Gas reserves and production

Gas reserves

The balance recoverable reserves of natural gas increased steadily from 1975 to 1999 but are now declining.

Table 14.1.1 State-wise reserves of natural gas (BCM)

Gas reserves (BCM)	1975	1980	1985	1990	1995	1998	1999 (P)
Onshore							
Gujarat	15.72	16.39	21.87	92.58	89.88	84.24	
Assam	65.24	63.53*	87.67*	135.47*	159.18*	187.73	
Rajasthan	0.43	0.43	0.54	1.04	4.11	4.44	
Total	**81.39**	**80.95**	**110.08**	**229.09**	**253.17**	**276.41**	279
Offshore							
Bombay High	6.28	270.96	368.55*	457.36	406.47**	398.34	369
Grand Total	**87.67**	**351.91**	**478.63**	**686.45**	**659.64**	**674.75**	**648**

* includes natural gas reserves in Tripura, Nagaland Tamil Nadu, Arunachal Pradesh & Andhra Pradesh

** includes natural gas reserves in Andhra Pradesh, Gujarat, Tamil Nadu, Andaman and JVC

Source. Indian Petroleum & Natural Gas Statistics - 1997-98 and 1998-99, Ministry of Petroleum & Natural Gas, Govt. of India

According to the Ministry of Petroleum and Natural Gas, the onshore and offshore gas reserves in the country in 1999 and 2000 were as follows.

Table 14.1.2 Gas reserves in 1998/99 (BCM)

Natural gas reserves	1998	1999
Onshore	277	279
Offshore	398	369
Total	**675**	**648**

Source. Indian Petroleum & Natural Gas Statistics - 1997-98 and 1998-99, Ministry of Petroleum & Natural Gas, Govt. of India

Unless reserves in existing fields are significantly upgraded or new fields discovered and brought on stream, gas production is set to decline from its current level.

Gas production

Natural gas production in India has grown from 2.4 BCM in 1975/76 to 28.5 BCM in 1999/00.

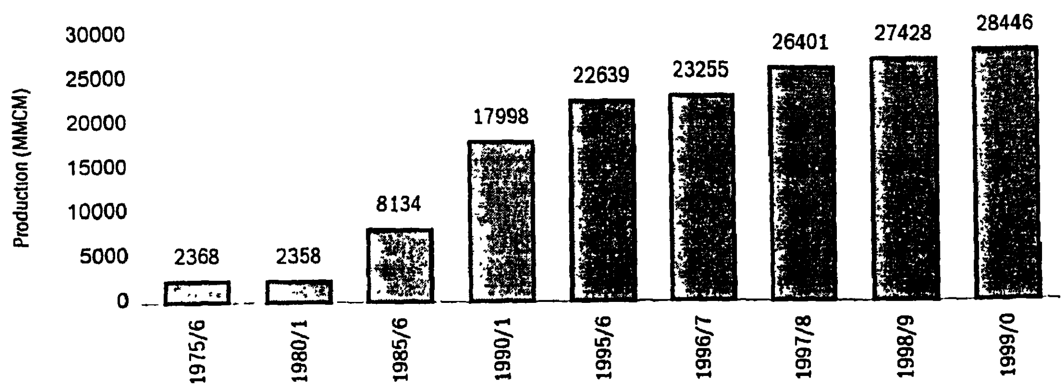


Figure 14.1.1 Gas production in India in million cubic metres

Source. Basic statistics on Indian Petroleum and Natural Gas, 1999-2000, Ministry of Petroleum & Natural Gas, Govt. of India

There are five major areas of gas production in India today:

- The Western Offshore region which extends from offshore Bombay to Gujarat
- North and South Gujarat
- The Krishna Godavari basin in Andhra Pradesh
- The Cauvery basin in Tamil Nadu
- Assam and Arunachal Pradesh

Currently around 75% of India's gas is being produced from the western offshore fields.

Gas supply sector organization

The gas supply sector in India is dominated by public sector enterprises under the administrative control of the Ministry of Petroleum. Ninety percent of the gas is produced by two state owned oil companies, the Oil and Natural Gas Corporation (ONGC) and Oil India Limited (OIL). The balance comes mostly from the medium sized fields - Panna, Mukta and Tapti in the western offshore and Ravva off the Andhra coast - operated by joint ventures of ONGC. Several small gas fields operated in the private sector are also producing gas but their production does not add up to much.

The gas produced by ONGC is marketed by GAIL except gas from isolated marginal fields marketed direct by ONGC. OIL, which operates mainly in Assam and also in Rajasthan sells gas mainly through its own arrangements and partly through GAIL. The gas from Panna-Mukta-Tapti and Ravva is bought by GAIL on behalf of the government. All of this gas is sold only to consumers who are allocated gas by the Government of India. The private operators of small gas fields are free to select their customers. The gas price to be charged by ONGC and OIL and the transportation charges along the HBJ pipeline of GAIL are fixed by the government. Gas from private fields is sold at negotiated prices.

The gas industry infrastructure

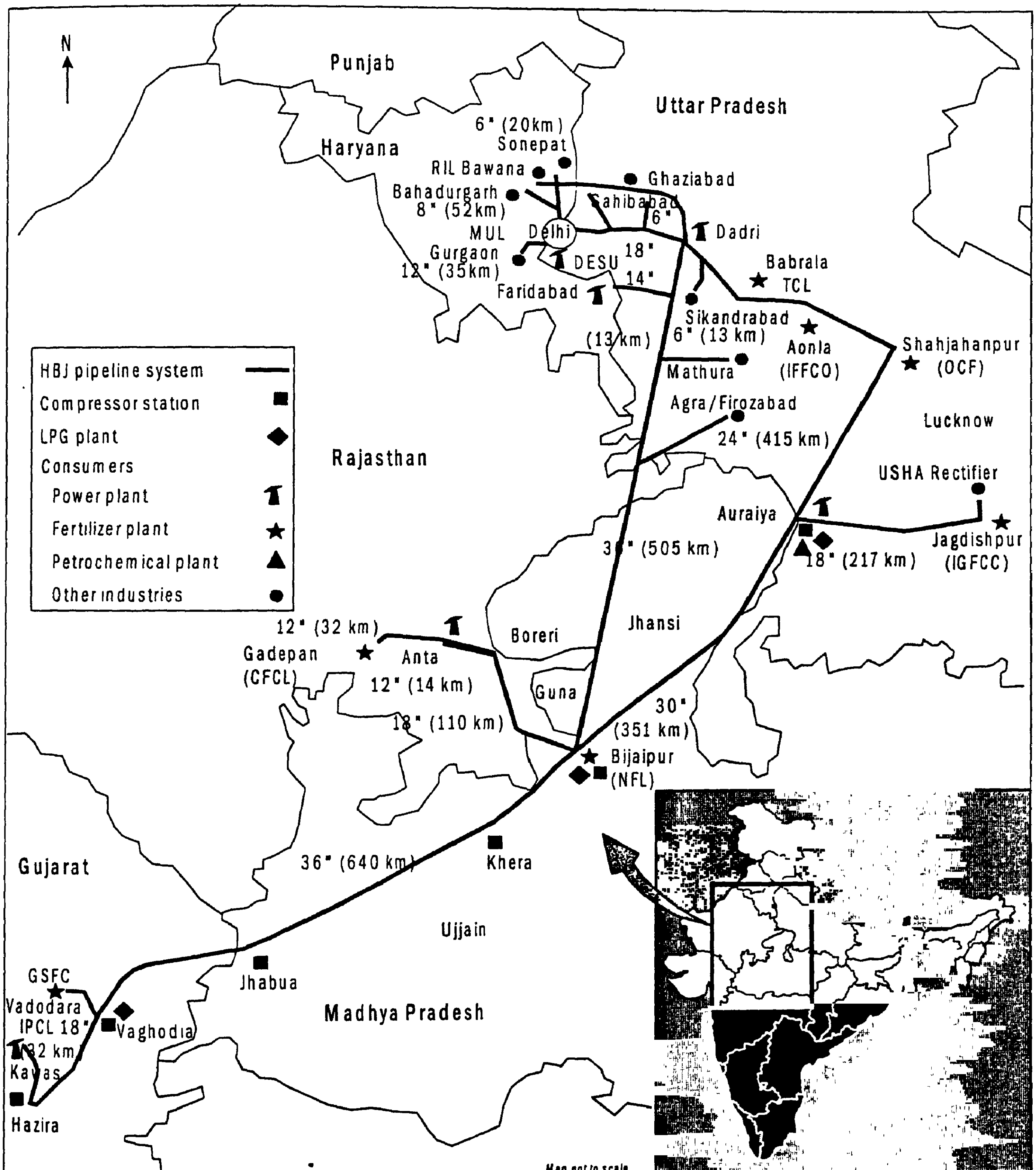
The Hazira-Bijaipur-Jagdishpur (HBJ) gas pipeline network (Map14.1.1) is the major gas transmission line in India, owned and operated by the Gas Authority of India Limited (GAIL). It starts at Hazira in Gujarat and passes over Rajasthan, Madhya Pradesh, Uttar Pradesh into Haryana. It is 2300 km long with a capacity of 33.4 MMCMD. Spur lines at various points in Gujarat, Rajasthan, Uttar Pradesh, Delhi and Haryana feed power plants, fertiliser plants and industries.

Wet gas from the offshore South Bassein field, off the coast of Maharashtra, is fed by 216 km sub-sea lines of 36" and 42" diameter to ONGC's sweetening and fractional separation plant at Hazira. The gas handling capacity at the Hazira terminal is 41 MMCMD.

With several LNG terminals being planned on the west coast of India, GAIL plans an investment of Rs. 30 billion to expand the HBJ capacity to 60 MMCMD by 2003. GAIL also plans to extend the HBJ pipeline to Ludhiana in Punjab.

Map 14.1.2 The HBJ (Hazira-Bijaipur-Jagdishpur) gas transmission system

Figure 8.2. HBJ (Hazira-Bijaipur-Jagdishpur) gas transmission system



In addition to the HBJ pipeline, there are regional gas grids of varying sizes in the states of Gujarat, Andhra Pradesh, Assam, Maharashtra, Rajasthan, Tamil Nadu and Tripura. Most of these regional pipelines (about 725 km) were constructed and operated by ONGC but ownership and operation of these gas grids were passed on to GAIL in the nineties. The present grid capacity is based on the gas availability from the producing areas as well as the outlook for future gas production. In view of the increased availability of gas in the KG basin, GAIL has announced plans for augmenting pipeline capacity in Andhra Pradesh.

Distribution

The Mahanagar Gas Limited, a joint venture between GAIL and British Gas is supplying gas to around 50,000 houses in Mumbai as well as small industrial and commercial units and CNG filling stations. The Indraprastha Gas Limited, a joint venture of GAIL and BPCL is supplying gas in Delhi to around 1000 houses and 80 CNG stations. At the instance of the Supreme Court, the fleet of buses, taxis and rickshaws in Delhi is being converted to CNG. The other cities with natural gas distribution systems are Vadodara, Surat and Ankleshwar in Gujarat and a few towns in Assam and Tripura in the north-east.

Exploration prospects and present activity

Sedimentary basins in India

There are 26 sedimentary basins in India extending over 1.39 million square kilometres onshore, 0.4 million square kilometres offshore and about 1.35 million sq. km in deep waters.

The basins have been categorized according to their prospectivity; Category I consist of producing basins, while Categories II to IV are basins with reducing prospectivity. The Category I basins include:

- Cambay Basin, Gujarat
- Bombay Offshore
- Cauvery Basin
- Krishna-Godavari Basin
- Assam Shelf/Assam Arakan Fold Belt

Exploration during the 1960s and 1970s was concentrated in category I basins. The three main producing basins in the country, the western offshore region, the Cambay basin in Gujarat, and Upper Assam region, are in the mature phase of exploration and with the exception of Assam, future finds in these areas are not

likely to be large in size. The deep water basins now being explored hold some promise of large discoveries.

Although the state owned enterprises increased hydrocarbon production and the reserve base significantly over the period 1975 to 1990, the gap between domestic production and demand widened in the later years. As a result, steps were taken to encourage private sector investment into exploration and production with exploration acreage offered to private companies under production sharing arrangements with the Indian government. Nine rounds of bidding were followed in 1999 by the New Exploration Licensing Policy (NELP) offering a level playing field to private and public sector oil companies. The first round of the NELP was launched in 1999. 25 blocks from this round were awarded last year and these have started showing results with discoveries offshore Gujarat and Andhra Pradesh. Exploration in the other blocks is in progress. With $250 million committed to be spent by the exploring companies, there is expectation of more oil and gas finds. Subsequently, 23 blocks have been awarded in the second bidding round launched in late 2000.

Alternative sources of gas

Coal bed methane (CBM)

The production of natural gas from coal – coal bed methane (CBM) – has been undertaken in several countries over the last decade, especially in the United States. India holds significant prospects for exploitation of CBM as a new source of energy. There are about 200 billion tonnes of coal reserves predominantly in the eastern part of India – Bihar, West Bengal and Madhya Pradesh. It is estimated that 70 –75 billion tonnes of coal reserves are beyond 600 metres in depth and thus not extractable with the current mining technologies. These reserves would potentially be available for exploitation of CBM. The existence of gaseous mines is well established in India, notably in Damodar Valley coal fields in Bihar and Bengal. Analysis of the coal in the Damodar Valley has indicated that upto 10 cubic metres of methane gas per tonne of coal may be present at a medium depth of burial.

There are large lignite reserves in Gujarat at the depth of 1,000 – 1,500 metres. GAIL and ONGC have agreed to jointly undertake a project for assessing the CBM potential of coal deposits in north Gujarat.

After taking into account the future coal- mining programme by coal companies, 7 blocks have been offered for exploration and exploitation through global competitive bidding by the government. The prognosticated CBM

resource in these blocks is around 400 BCM as estimated by the Director General of Hydrocarbons (DGH).

Table 14.1.3 Prognosticated CBM resources

Coalfield	Block/State	Area covered (in sq. k.m.)	Prognosticated CBM resource (in TCF)
Gondwana Coal			
Raniganj	Norhtem Raniganj (West Bengal)	232.00	1.030
Raniganj	Eastem Raniganj (West Bengal)	500.00	1.850
Jharia	Southem part of Jharia Coalfield (Bihar)	69.20	2.407
Bokaro	Bokaro Basin (Bihar)	93.97	1.590
Birbhum	Birbhum (West Bengal)	250.00	1.000
N. Karanpura	N. Karanpura (Bihar)	340.54	2.181
Sohagpur	Eastem Sohagpur (M.P)	495.00	3.030
Sohagpur	Westem Sohagpur (M.P)	500.00	
Satpura	Satpura Basin (M.P)	500.00	1.000
Total		2980.71	14.088 or 398.92 BCM gas in place

Source. Hydrocarbon Vision 2025, GoI

These resources can yield an average production level of 22 MMCMD for a period of 25 years, assuming a recovery factor of 60%. Bids received for the blocks is now under evaluation.

Demand for natural gas

Past trends in gas demand

Although the use of natural gas has increased rapidly, natural gas accounts for only around 11% of the primary energy in use. Till the late 1980s the demand lagged behind the production potential mainly because of lack of infrastructure. However, in the 90's, the demand has exceeded the supply.

In view of the shortage of gas, the government of India allocates gas to all consumers. The power and fertilizer sectors have been allocated most of the gas. These two sectors together consume about 80% of the gas today. The sponge iron units consume another 10%. The balance goes to industrial units where it replaces mostly fuel oil and some LPG. As noted earlier, gas is also supplied to the residential and the commercial sectors in Mumbai, Delhi and a few towns of Gujarat, Assam and Tripura. This gas is used for cooking only, as space heating is not required. The daily requirement of households is only around 1 cum. With such low requirements and the subsidy on domestic LPG, the demand from this sector will continue to be low. The use of CNG in lieu of petrol has been popular in Mumbai and Delhi.

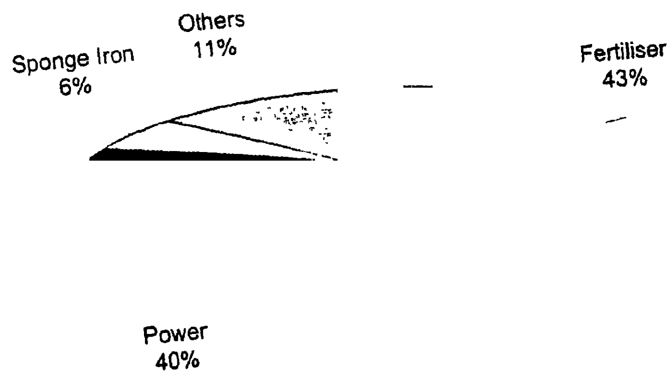


Figure 14.1.2 Sectoral gas sales (1998/99)
Source. GAIL

Area wise and sector wise use of natural gas in 1998/99 was as shown in the Table below:

Table 14.1.4 Gas utilization: 1998/99 (MMCMD)

Area	Fertilizer	Power	Sponge Iron	Others	Total
Western Offshore	5.0	4.7	1.4	0.7	11.8
Uran	13.0	9.1		2.5	24.6
HBJ	2.7		2.0	1.2	5.9
Hazira	1.2	4.2		1.4	6.8
Western Onshore		0.4			0.4
Rajasthan	1.7	2.2		0.1	4.0
K. G. Basin	0.0	0.4		0.1	0.6
Assam		0.8		0.0	0.8
Tripura		0.0		0.1	0.1
Cauvery Basin					
Total	23.6	21.9	3.5	6.1	55.1

Source. GAIL

Among the states, Gujarat uses more gas than any other state in India.

Gas use in fertilizer industry and power generation

The fertilizer industry is currently the largest single gas consumer in India accounting for about 44% of the total sales. Gas utilization for fertilizer production in India started in earnest in the early 1980s.

The choice of feedstock for fertilizer production has been primarily determined on the basis of availability of feedstock and government policies in place. Immediately following the fertilizer industry, the power sector is the second largest consumer of gas in India.

Other industries

Gas utilization is preferred in industries where heat control and low sulphur are prerequisites in the fuel used such as glass, ceramics, textiles, electronics (picture tubes) etc. It is also used in the sponge iron (or DRI) industry and in the production of methanol.

The sponge iron industry

In the sponge iron industry, natural gas is used as a primary agent for the reduction of iron oxides into metallic iron, either in the form of Hot Briquetted Iron or iron carbide, for subsequent use in the manufacture of steel slabs and billets. DRI is a substitute for the use of scrap as a feedstock in arc and blast furnaces. The Midrex process is used in India by both Essar and Vikram Ispat at Hazira and Raigarh respectively, whilst the HYL III process is used by Grasim, also at Raigarh.

The production of methanol

Natural gas is the dominant feedstock for production of methanol through the partial oxidation process. Methanol is one of the major basic chemical raw materials. At present methanol production in India from gas is limited to a single plant in Gujarat operated by Gujarat Narmada Fertilizer Company.

The glass and ceramics industry

Gas is used in the glass and ceramics industry to fire furnaces in which the raw materials, fluxes and oxidising agents are mixed. The demand from the glass industry is relatively low – a typical glass plant would consume no more than 0.1 MMCMD. The glass industry will be a willing consumer of gas but will not be able to provide an anchor load.

Other areas of gas use

Gas is also used in industries for process heating and steam–raising. Oil refineries use some gas to produce H_2 for de-sulphurisation and hydro-cracking.

The domestic sector

For domestic consumers, the main use of gas will be in replacing kerosene and LPG for cooking. Domestic consumers have to piggyback on large consumers as the city distribution projects would not be viable otherwise.

Expected trends in gas demand

The demand for gas up to 2025, the indigenous supply and the deficit have been examined in the Hydrocarbon Vision 2025 brought out recently by the Government of India. The requirement of gas over this time horizon would depend upon a number of factors and their complex inter-relationship. The growth in energy consumption would depend upon the growth of population and of GDP, the structural changes in GDP, the growth of industrial and agricultural sectors, energy pricing and tariffs and the success of energy conservation measures based on the need to contain damage to the environment.

According to the Vision document, the power and the fertiliser sectors would dominate gas consumption and the demand would build up as shown below.

Table 14.1.5 Total gas demand (MMCMD)

	1998/99	2001/02	2006/07	2011/12	2024/25
Power					
Scenario 1*	22	40	67	90	153
Scenario 2**	22	67	119	168	208
Fertilizer	24	54	66	83	105
Others#					
Scenario 1	9	23	33	43	64
Scenario 2	9	30	46	63	78
Total					
Scenario 1	55	117	166	216	322
Scenario 2	55	151	231	313	391

* gas at $4/MMBtu

** gas at $3/MMBtu

\# other sectors account for 20% of total demand in 2002 and thereafter

Source. Hydrocarbon Vision 2025, GOI

Our own estimates of gas demand are more conservative, as we shall see in the next chapter.

Future gas production projections

ONGC draws up long term profiles of gas production every year. These are based on development plans already finalized as well as in anticipation of future discoveries. Current projections show that the total gas production would decline steadily until the Bombay High gas cap is brought into production. This is expected between the years 2015 and 2020.

Demand - supply balance

The declining production profile coupled with the projection of rising demand shows a widening demand-supply gap. This implies that exploration efforts need to be stepped up and the feasibility of importing gas from the neighbouring countries examined seriously. The initiatives and prospects for exploration have been described earlier. The options for importing gas through pipelines are outlined below.

Pipeline gas import projects

Oman - India deep water pipeline

An in-principle agreement was signed by the governments of India and Oman in September 1994 for the import of 56.6 MMCMD of gas through two sub-sea pipelines. The gas from the first pipeline was to be utilized in western and northern India and the second was planned to be taken to south India. In order to avoid the territorial waters and the Exclusive Economic Zone (EEZ) of Pakistan, a deep-sea route was proposed. Parts of the route lay at water depths exceeding 3000 metres. The Oman Oil Company could not develop the necessary technology to lay pipelines at that depth. Also, the proven gas reserves in Oman did not support both the pipeline and the LNG Projects. As a result, the pipeline proposal has not been seriously pursued after 1997.

Iran - Pakistan - India

India and Iran signed a MoU in 1993 to study the feasibility of importing 50-75 MMCMD of gas through a pipeline landing in Kachchh in India. A shallow offshore route through the EEZ of Pakistan was proposed. A feasibility study was awarded to PLE of Germany. However, work on the feasibility study could not be started as the government of Pakistan did not permit the route survey. An onland alternative through Pakistan has also been under consideration. Pakistan had favoured this option but the Indian side has worried about the security of supplies. Progress on the project will be possible only when the relations between India and Pakistan improve.

Bangladesh - India pipeline

Unocal and Shell have led the efforts being made to import gas from Bangladesh to India. Unocal has proposed pipelines from the Bibiyana fields in Bangladesh whereas Shell has proposed bringing gas from the Sangu fields in offshore Bangladesh. Some of the proposals involve small quantities to be brought to Bengal. Among the larger proposals, Unocal has envisaged bringing 500 mcfd to

be fed into the HBJ. A consortium of ONGC, IOC and GAIL would market the gas. Bangladesh has so far not agreed to export proposals on the ground that the gas is required for consumption within Bangladesh. However, the Bangladesh government has recently formed a Committee to look into gas utilisation. The future of these proposals will depend on the recommendations of the Committee.

Myanmar - Bangladesh - India

GAIL has an MOU with Cairns Energy / Shell and Halliburton for the study of a 1 bcfd pipeline from Myanmar via Bangladesh. The proposed pipeline alignment covers Orissa, Andhra Pradesh, the eastern portion of Karnataka and Tamil Nadu. Myanmar is yet to prove sufficient gas reserves to support such a project.

Turkmenistan - Afghanistan - Pakistan - India

This proposal was pursued by Unocal of USA under the Centgas consortium, for bringing gas from Turkmenistan's Dauletabad fields to markets in northern Pakistan, with the potential of an extension from Multan to New Delhi, India. Unocal formally withdrew from the venture in 1998 on account of the situation in Afghanistan. The recent changes in Afghanistan will no doubt re-generate interest in the proposal.

Qatar - India

A proposal for bringing gas by pipeline from Qatar through Pakistan has been promoted by Crescent Company of Sharjah but little progress has been made.

The projects listed above are considered economically viable. The problems are political in nature and an early solution of the problems is unlikely.

Import of LNG

The status of LNG import projects is examined in Annexure 14.5 of this report.

Domestic gas price

The price of gas sold by ONGC through GAIL, the price of gas from fields operated by joint ventures and also transportation charges along the HBJ are fixed by the Government. Gas from private fields are sold at negotiated prices.

The price of natural gas has been fixed by the Government since 1987. In 1987, the price was Rs 1400/mcm for gas at landfall points and a flat Rs 2250/mcm for gas along the HBJ line. The gas price was much lower than the

prices of alternative fuels and the government felt the need to bring the price to the consumer in line with these prices.

The Kelkar committee was appointed in 1990 to recommend revisions in the gas prices. The committee recommended that the price payable to the producers be fixed on the basis of the long run marginal cost of production estimated at Rs 1500/mcm. The consumer price was to be increased annually to reach Rs 1850/mcm, which was near enough to the prevailing fuel oil price. The difference between the consumer price and the producer price was credited to the Gas Pool Account – an account set up to compensate ONGC and OIL for the concessional price of gas in the North-East.

In 1996 the Sankar Committee was established to review the above rates, with some consideration given to the impending need for gas imports and the effects of import parity pricing. The committee decided that import parity pricing would be too steep a transition. The committee left intact the principles of fixing the producer price and the consumer price earlier recommended by Kelkar. The prices were however revised upward based on fresh estimation of the costs.

Having considered these recommendations, in October 1997 the government instituted a new series of gas prices, valid through to March 31, 2000. The consumer price of gas at landfall points were linked to the price of a basket of fuel oils as shown in the table below.

Table 14.1.6 Natural gas pricing against a basket of fuel oils (%)

Year	Percentage of LSHS/FO pnce	
	General pnce	Concessional pnce for the NE states
1997-98	55	35
1998-99	65	40
1999-2000	75	45

The price is determined and notified by GAIL with the approval for the Ministry for every quarter depending upon the average price of the following basket of fuel oils (with equal weights to each type) based on the figures obtained from Platt's Oilgram for the previous quarter.

- Cargoes FOB, Med Basis, Italy (1% Sulphur)
- Cargoes CIF NEW Basis, ARA (1% Sulphur)
- Singapore, FOB, HSFO 180 cst (3.9% Sulphur)
- Arabian Gulf, FOB, HSFO 180 cst (3.9% Sulphur)

The price varies between the floor of Rs 2150/mcm and the ceiling of Rs 2850/mcm. This consumer price of gas is linked to a calorific value of 10000 kcal/m^3. The price has now reached the ceiling and is being reviewed with a view to introducing 100% fuel oil parity prices.

ONGC/OIL/GAIL and joint venture operations are permitted to sell gas from marginal isolated fields to be developed in future, at market driven prices.

The transportation charge along the HBJ pipeline was fixed at Rs 1150/mcm and has increased since 1997 by 1% for every 10% increase in the consumer price index. This increase is paid to GAIL out of the Gas Pool Account. The transportation charge has been linked to the calorific value of 8500 Kcal/m^3. Out of the consumer prices collected by GAIL, GAIL retains the amount required to pay for the higher cost of gas purchased from the joint venture companies who are paid full fuel oil parity prices.

The above prices are applicable to gas sold by ONGC or OIL to GAIL and to sales by GAIL to consumers. Sales by private field operators are linked to fuel oil prices. The prices applicable at different interfaces are as shown below.

Gas sales by ONGC/OIL to GAIL

As detailed above.

Gas sales by private upstream companies

To GAIL

These are negotiated between the government and the private operators and included in the production sharing contracts. So far these prices have been full fuel oil parity prices but the fuel oils basket could differ from one case to another.

Direct to end-users

These are freely negotiated and are mostly linked to prices of alternative fuels. Transportation charges are also negotiated.

Gas sales by GAIL to end-users

As detailed above. The transportation charge on the HBJ pipeline provides GAIL a 12% post-tax return on net worth. The transportation charges on other pipelines is fixed by GAIL on the same principle.

Gas sales by GAIL to distribution companies

The distribution companies pay the same price to GAIL as any other customer.

Gas sales by distribution companies to end-users

These are negotiated prices linked to alternative fuels.

Taxes and duties

In addition to the price as fixed above, royalty, taxes, duties and other statutory levies on the production and sale of natural gas is payable by the consumer. The royalty on gas as fixed under the Oilfields Development Act is 10% of the wellhead price. There is no cess on natural gas (unlike crude oil) although a cess could be levied under the law. There is no excise duty as natural gas or on crude oil as these are minerals although excise duty is charged on petroleum products. A sales tax is leviable at state rates if the sale is within the state or at the central rate of 4% for inter-state sales. The state sales tax rates vary from one state to another, ranging from zero to 22%.

A typical price build up for gas produced in a state and sold within the state would be as below.

	$ / MMBtu
Gas price	1.80
Royalty	0.18
Transportation charge	0.43
Sales tax (20%)	0.48
Total	2.89

It is to be noted that GAIL does not make a margin on merchant sales; it is allowed a return only on its investment in the pipeline.

In addition to this, there would be a customs duty to be paid on imported gas/LNG. This duty is now 5%. A countervailing duty of 16% was levied till last year on LNG except when used for power generation. This has now been removed so that the duty is now the same for all consumers. The gas industry has been asking for 'infrastructure' status, with a consequent reduction in the customs duty to be paid on components imported for pipelines and LNG receiving terminals. The concession, if granted, could make a difference of around 7-8 cents/mmbtu in the regasification cost. However, there is no guarantee that the benefit would be passed on to the consumer. The government has not yet agreed and is not likely to agree.

Contractual arrangements for sale of gas

There is no contract as yet between ONGC and GAIL regarding gas supplied by the former to the latter. This has not given rise to major problems as both are public sector undertakings. For supplies to its consumers, GAIL has evolved a

standard contract to which case-specific small variations can be made. The major points covered in such contracts are:

- *Period of contract*: The period is between 10 and 15 years from the date of commencement of supply.
- *Activity milestones for new customers*: The contract spells out the dates of completion of major activities for new plants like purchase of land, ordering of equipment, commencement of construction, completion of construction, etc. The contract requires all purchasers to lodge with GAIL a refundable cash deposit and a bank guarantee (equivalent to about three times the cash deposit). GAIL is required to pay interest on the cash deposit. The contract also stipulates that GAIL has the right to forfeit 25% of the bank guarantee for delay in completion of any of the stipulated major activities in a new plant beyond three months of the milestone schedule. The right of GAIL to cancel the contract for further delays in construction activities is also incorporated in the contract.
- *Manner of delivery of gas*: The inlet pressures, location of the Gas Metering Station, its installation and maintenance by the seller at the consumer's cost and provision of a check metering station by the consumer, are provided in the contract. Besides, frequency and method of calibration of metering unit are specified.
- *Quantity of gas*: The progressive schedule of delivery is indicated in the contract in terms of daily quantity. However, prior to each contract year the customer is required to indicate a forecast of gas requirement. The customer guarantees a minimum off-take of around 80% of the contracted quantity and payments being made up to this 80% level even when the off-takes are lower (take or pay).
- *Specification of gas*: The quality of gas to be supplied and the method to be followed for gas sampling is annotated. Typical limits of composition of the gas at the delivery point are indicated.
- *Price of gas*: This is as decided by the GOI in its price notification that is issued periodically. In addition transportation charges, royalty, taxes, duties and other statutory levies of the Central/State Government or any other local bodies are borne by the buyer.
- *Transport cost*: This is either a fixed amount as for delivery ex-HBJ pipeline or according to a formula, where a new gas line is laid for making supplies of gas available to a consumer. In respect of existing customers outside the HBJ pipeline, the transport charges as earlier agreed mutually between the supplier and consumer will continue. However, for future the new formula

will be relevant. This formula covers annual depreciation of pipeline cost, reasonable return on capital cost of the pipeline and its operation and maintenance costs. The transport cost is subject to escalation at 3% per annum.

- *Billing and payment terms*: Invoices are submitted fortnightly and customers are to pay within 3 working days of presentation of an invoice. The customer has to open and maintain an irrevocable Letter of Credit with a bank notified by the seller, covering a value of fifteen days supply of gas at maximum contracted quantity and the monthly transportation charge. If, for any reason, payment is delayed or any disallowance made from the invoice, the seller may present the invoice for the full amount or for the amount not paid, as the case may be, to the bank against the Letter of Credit and draw the amount. For supplies to continue, the customer has to reinstate the full amount of L/C.
- *Arbitration*: This is generally guided by the provisions of Indian Arbitration Act. Besides, other Indian Laws relating to contract, etc. are fully applicable.

GAIL's contracts with consumers have been criticised as being one-sided. While GAIL is protected by take-or-pay provisions, there is no penalty on GAIL for short-supply.

Issues in gas contracts

Some of the important points in respect of these contracts between different parties are listed below. First, different prices prevail at different locations depending on the transportation cost and sales tax, but no distinction is made currently between different categories of consumers in the same location with reference to the opportunity value of gas they use. Secondly, supplies of gas to all categories are non-interruptible, except for those delivered to "fall-back" customers. Currently to avoid under-utilisation of available gas, allocations are made in excess of the availability. This requires rationing of gas and the use of alternative fuels. While dual-fuel arrangements were earlier made only as exceptions, the Government now insists on dual-fuel arrangements for all customers. Thirdly, GAIL today discharges the role of both a transporter and a merchant. In the few cases where ONGC and OIL sell gas direct to consumers, they also provide 'bundled' services.

Annexure 14.2
Estimation of gas demand

Power generation

The demand for electricity for past years can be computed by adding the actual consumption and the shortages, both reported by the Central Electricity Authority (CEA). As shown in the Table below, the demand has grown quite rapidly in the recent years.

Table 14.2.1 Statewise electricity demand 1998/99 to 2000/1 (MU)

	1998/99	1999/00	2000/01	Growth rate %
Delhi	16573	17946	19340	8.0
Haryana	14162	15423	16657	8.5
Himachal Pradesh	2896	3123	3502	10.0
Jammu & Kashmir	5792	7145	7435	13.3
Punjab	24886	26223	28621	7.2
Rajasthan	23802	26210	27792	8.1
Uttar Pradesh	42619	49409	53502	12.0
Chandigarh	1033	1117	1201	7.8
Goa	1700	1966	1846	4.2
Gujarat	41702	45412	48911	8.3
Madhya Pradesh	35369	38602	42163	9.2
Maharastra	66129	74335	82918	12.0
Dadar & Nagar Havelli	727	793	858	8.6
Daman & Diu	442	488	534	9.9
Andhra Pradesh	42077	47218	51056	10.2
Kamataka	30312	31184	33546	5.2
Kerala	12608	13573	14803	8.4
Tamil Nadu	41440	41274	43390	2.3
Pondicherry	1278	1478	1673	14.4
Bihar	14210	14530	15354	3.9
Orissa	11272	12034	12735	6.3
Sikkim	122	137	171	18.4
West Bengal	19478	20985	22450	7.4
Arunachal Pradesh	182.7	186.1	198.6	4.3
Assam	2894.1	3084.9	3159	4.5
Manipur	486.7	548.3	594.5	10.5
Meghalaya	465.1	512.3	559.7	9.7
Mizoram	247.4	264.9	289.2	8.1
Nagaland	225.4	229.8	244.1	4.1
Tripura	514.6	518.8	556.6	4.0
All India	455771	496092	536220	8.5

It is to be noted that the above figures refer to the demand at the bus bar and therefore include the T&D losses.

The last demand projection made by CEA was published in 2000 as the 16th Electric Power Survey (EPS). The 16th EPS has made annual projections up to

2004-05 and long-term projections for 2006-07, 2011-12, and 2016-17, the terminal years of the 10th, 11th and the 12th five-year plans. The projections are based on the analysis of past trends in electricity consumption in the following sectors:

- Domestic
- Commercial and miscellaneous
- Public lighting
- Public water works
- Irrigation and dewatering
- Industrial (HT above 1 MW, HT below 1 MW and LT)
- Railway traction and
- Bulk supply to non-industrial consumers

CEA holds extensive discussions with the power utilities in each state before making these projections. One major problem that makes such projections difficult is that agricultural supplies are not metered. The other problem is that there are large commercial losses. Both of these factors distort the sectoral consumption figures. In spite of this problem, earlier projections by CEA conform quite closely to the unrestricted demand. The growth in internet connections will lead to a high demand in the domestic sector. According to CEA, the latest projections take this into account. The statewise projections are shown in the Table below.

Table 14.2.2 Projections of energy demand (MU)

State	2001-02	2006-07	2011-12	2016-17
Northern region				
Haryana	17460	25750	37801	55234
Himachal Pradesh	3656	5113	7118	9863
Jammu & Kashmir	6796	9099	12125	16081
Punjab	29824	41922	58661	81700
Rajasthan	28852	40341	56133	77741
Uttar Pradesh	50087	70803	99631	139542
Chandigarh	1337	2120	3347	5259
Delhi	19454	25672	33712	44060
Sub Total	**157466**	**220820**	**308528**	**429480**
Western region				
Goa	1740	2207	2786	3501
Gujarat	46393	61683	81615	107479
Madhya Pradesh	39167	51952	68578	90096
Maharashtra	79593	106892	142911	190167
D&N Haveli	923	1284	1779	2452
Daman & Diu	585	909	1406	2164
Sub Total	**168401**	**224927**	**299075**	**395859**
Southern region				

State	2001-02	2006-07	2011-12	2016-17
Andhra Pradesh	50493	68797	93289	125905
Kamataka	32950	44748	60478	81354
Kerala	15378	22998	34231	50718
Tamil Nadu	42341	54872	70769	90838
Pondicherry	1818	2687	3951	5784
Sub Total	**142980**	194102	262718	**354599**
Eastem region				
Bihar (excl. DVC)	9303	12256	15814	20308
DVC	9213	11129	13365	15974
Onssa	14002	17997	23376	30220
Sikkim	183	239	312	405
West Bengal (excl. DVC)	20885	27846	37529	50341
Sub Total	**53586**	**69467**	**90396**	**117248**
North-East region				
Arunachal Pradesh	216	303	423	588
Assam	3669	5294	7604	10870
Manipur	643	1039	1672	2679
Meghalaya	644	955	1410	2071
Mizoram	327	525	838	1331
Nagaland	270	388	555	790
Tripura	635	997	1559	2427
Sub Total	**6404**	**9501**	**14061**	**20756**
Islands				
Andaman & Nicobar	**148**	**236**	**374**	**591**
Lakshadeep	**28**	**44**	**70**	**111**
Total	**529013**	**719097**	**975222**	**1318644**

The elasticity of electricity consumption with respect to the GDP was 1.10 in the nineties. Assuming a growth of 6% in GDP over the next six years, the elasticity is projected to come down slightly as shown in the Table below.

Table 14.2.3 Elasticity of electricity consumption

Penod	2001-2007
Elasticity	1.06

The current installed capacities (as on 31 May 2001) in the states are shown below.

Table 14.2.4 Installed capacity in the states (MW)

State	Sector	Total	Hydel	Coal	Gas	Diesel	Total Thermal	Wind	Nuclear
Northem region									
Delhi	**State**	**617**	**0**	**335**	**282**	**0**	**617**	**0**	**0**
	Private	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Center	**2308**	**217**	**1797**	**207**	**0**	**2004**	**0**	**87**
Total		**2925**	**217**	**2132**	**489**	**0**	**2621**	**0**	**87**
Haryana	**State**	**1990**	**884**	**1103**	**0**	**4**	**1106**	**0**	**0**
	Private	0	0	0	0	0	0	0	0

State	Sector	Total	Hydel	Coal	Gas	Diesel	Total Thermal	Wind	Nuclear
	Center	1290	314	383	534	0	917	0	59
	Total	**3280**	**1198**	**1486**	**534**	**4**	**2023**	**0**	**59**
Himachal Pradesh	State	324	324	0	0	0	0	0	0
	Private	0	0	0	0	0	0	0	0
	Center	239	109	54	62	0	116	0	14
	Total	**563**	**433**	**54**	**62**	**0**	**116**	**0**	**14**
Jammu & Kashmir	State	417	233	0	175	9	184	0	0
	Private	0	0	0	0	0	0	0	0
	Center	709	433	114	129	0	243	0	33
	Total	**1126**	**666**	**114**	**304**	**9**	**427**	**0**	**33**
Punjab	State	4529	2399	2130	0	0	2130	0	0
	Private	0	0	0	0	0	0	0	0
	Center	1216	456	406	264	0	670	0	90
	Total	**5745**	**2855**	**2536**	**264**	**0**	**2800**	**0**	**90**
Rajasthan	State	2492	972	1475	39	0	1514	6	0
	Private	1	0	0	0	0	0	1	0
	Center	1942	207	453	358	0	811	0	924
	Total	**4434**	**1179**	**1928**	**397**	**0**	**2325**	**7**	**924**
Uttar Pradesh	State	5613	1511	4102	0	0	4102	0	
	Private	0	0	0	0	0	0	0	
	Center	2812	201	2085	482	0	2567	0	44
	Total	**8425**	**1712**	**6187**	**482**	**0**	**6669**	**0**	**44**
Chandigarh	State	2	0	0	0	2	2	0	0
	Private	0	0	0	0	0	0	0	0
	Center	68	33	15	15	0	30	0	5
	Total	**70**	**33**	**15**	**15**	**2**	**32**	**0**	**5**
Central Unallocated		**898**	**40**	**533**	**261**	**0**	**794**	**0**	**64**
Total Northern Region	**State**	**15983**	**6322**	**9145**	**496**	**15**	**9655**	**6**	**0**
	Private	**1**	**0**	**0**	**0**	**0**	**0**	**1**	**0**
	Center	**11482**	**2010**	**5840**	**2312**	**0**	**8152**	**0**	**1320**
	Total	**27466**	**8332**	**14985**	**2808**	**15**	**17807**	**7**	**1320**
Western region									
Goa	State	0	0	0	0	0	0	0	0
	Private	48	0	0	48	0	48	0	0
	Center	407	0	357	35	0	392	0	15
	Total	**455**	**0**	**357**	**83**	**0**	**440**	**0**	**15**
Daman & Diu	State	0	0	0	0	0	0	0	0
	Private	0	0	0	0	0	0	0	0
	Center	14	0	8	4	0	12	0	2
	Total	**14**	**0**	**8**	**4**	**0**	**12**	**0**	**2**
Gujarat	State	4584	547	3759	243	17	4019	17	0
	Private	2640	0	1060	1430	0	2490	150	0
	Center	1538	0	829	424	0	1253	0	285
	Total	8762	547	5648	2097	17	7763	167	285
Madhya Pradesh	State	4351	913	3438	0	0	3438	1	0
	Private	22	0	0	0	0	0	22	0
	Center	1618	0	1268	257	0	1525	0	93
	Total	5991	913	4706	257	0	4963	23	93
Maharashtra	State	9744	2400	6425	912	0	7337	6	0
	Private	3200	447	1650	920	0	2570	183	0
	Center	2028	0	1339	392	0	1731	0	297
	Total	14972	2847	9414	2224	0	11638	190	297
Dadra & Nagar Haveli	State	0	0	0	0	0	0	0	0

State	Sector	Total	Hydel	Coal	Gas	Diesel	Total Thermal	Wind	Nuclear
	Pnvate	0	0	0	0	0	0	0	0
	Center	16	0	9	5	0	14	0	2
Total		**16**	**0**	**9**	**5**	**0**	**14**	**0**	**2**
Central Unallocated		**891**	**0**	**650**	**175**	**0**	**825**	**0**	**66**
Total Western Region	**State**	18678	3860	13622	1155	17	14794	24	0
	Private	5910	447	2710	2398	0	5108	355	0
	Center	6512	0	4460	1292	0	5752	0	760
Total		31101	4307	20792	4845	17	25654	379	760
Southern region									
Andhra Pradesh	State	5879	2822	2953	99	0	3052	5	0
	Pnvate	880	0	0	793	0	793	87	0
	Center	1001	0	857	0	0	857	0	144
Total		**7760**	**2822**	**3810**	**892**	**0**	**4702**	**92**	**144**
Karnataka	State	4178	2788	1260	0	128	1388	3	0
	Pnvate	345	18	260	0	25	285	42	0
	Center	674	0	544 .	0	0	544	0	130
Total		**5197**	**2806**	**2064**	**0**	**153**	**2217**	**45**	**130**
Kerala	State	2032	1795	0	0	235	235	2	0
	Pnvate	186	12	0	174	0	174	0	0
	Center	804	0	398	350	0	748	0	56
Total		**3022**	**1807**	**398**	**524**	**235**	**1157**	**2**	**56**
Tamil Nadu	State	5222	1995	2970	237	0	3207	19	0
	Private	1429	0	0	331	306	636	793	0
	Center	1969	0	1611	0	0	1611	0	358
Total		**8620**	**1995**	**4581**	**568**	**306**	**5454**	**813**	**358**
Pondicherry	State	33	0	0	33	0	33	0	0
	Private	0	0	0	0	0	0	0	0
	Center	142	0	130	0	0	130	0	12
Total		**175**	**0**	**130**	**33**	**0**	**163**	**0**	**12**
Central Unallocated		**610**	**0**	**530**	**0**	**0**	**530**	**0**	**80**
Total Southern Region	**State**	17343	9400	7183	369	363	7914	29	0
	Private	2840	30	260	1298	331	1889	922	0
	Center	5200	0	4070	350	0	4420	0	780
Total		25383	9430	11513	2016	693	14222	951	780
Eastern region									
Bihar & Jharkhand	State	1988	175	1814	0	0	1814	0	0
	Pnvate	120	0	120	0	0	120	0	0
	Center	2731	84	2557	90	0	2647	0	0
Total		**4839**	**259**	**4490**	**90**	**0**	**4580**	**0**	**0**
West Bengal	State	3582	165	3305	100	12	3417	1	0
	Private	1202	0	1201	0	0	1202	0	0
	Center	1750	60	1690	0	0	1690	0	0
	DVC	263	0	263	0	0	263		
Total		**6797**	**225**	**6459**	**100**	**12**	**6796**	**1**	**0**
Orissa	State	2298	1877	420	0	0	420	1	0
	Private	0	0	0	0	0	0	0	0
	Center	1102	0	1102	0	0	1102	0	0
Total		**3400**	**1877**	**1522**	**0**	**0**	**1522**	**1**	**0**
Sikkim	State	38	33	0	0	5	5	0	0
	Pnvate	0	0	0	0	0	0	0	0
	Center	118	60	58	0	0	58	0	0
Total		**156**	**93**	**58**	**0**	**5**	**63**	**0**	**0**
Central Unallocated		**878**	**0**	**878**	**0**	**0**	**878**	**0**	**0**

State	Sector	Total	Hydel	Coal	Gas	Diesel	Total Thermal	Wind	Nuclear
Total Eastern Region	**State**	**7907**	**2250**	**5539**	**100**	**17**	**5656**	**2**	**0**
	Private	**1322**	**0**	**1321**	**0**	**0**	**1322**	**0**	**0**
	Center	**6842**	**204**	**6548**	**90**	**0**	**6638**	**0**	**0**
Total		**16070**	**2454**	**13407**	**190**	**17**	**13615**	**2**	**0**
North-eastern region									
Assam	State	597	2	330	245	21	595	0	0
	Private	25	0	0	25	0	25	0	0
	Center	349	171	0	178	0	178	0	0
Total		**970**	**173**	**330**	**447**	**21**	**798**	**0**	**0**
Arunachal Pradesh	State	45	30	0	0	16	16	0	0
	Private	0	0	0	0	0	0	0	0
	Center	43	22	0	21	0	21	0	0
Total		**88**	**52**	**0**	**21**	**16**	**37**	**0**	**0**
Meghalaya	State	189	187	0	0	2	2	0	0
	Private	0	0	0	0	0	0	0	0
	Center	70	44	0	26	0	26	0	0
Total		**259**	**231**	**0**	**26**	**2**	**28**	**0**	**0**
Tripura	State	85	16	0	65	5	69	0	0
	Private	0	0	0	0	0	0	0	0
	Center	64	31	0	33	0	33	0	0
Total		**149**	**47**	**0**	**98**	**5**	**102**	**0**	**0**
Manipur	State	13	3	0	0	9	9	0	0
	Private	0	0	0	0	0	0	0	0
	Center	77	50	0	26	0	26	0	0
Total		**89**	**54**	**0**	**26**	**9**	**36**	**0**	**0**
Nagaland	State	6	4	0	0	2	2	0	0
	Private	0	0	0	0	0	0	0	0
	Center	52	33	0	19	0	19	0	0
Total		**58**	**37**	**0**	**19**	**2**	**21**	**0**	**0**
Mizoram	State	37	8	0	0	29	29	0	0
	Private	0	0	0	0	0	0	0	0
	Center	31	15	0	16	0	16	0	0
Total		**68**	**23**	**0**	**16**	**29**	**45**	**0**	**0**
Central Unallocated		**119**	**64**	**0**	**56**	**0**	**56**	**0**	**0**
Total North Eastern Region	**State**	**973**	**250**	**330**	**309**	**84**	**723**	**0**	**0**
	Private	**25**	**0**	**0**	**25**	**0**	**25**	**0**	**0**
	Center	**805**	**430**	**0**	**375**	**0**	**375**	**0**	**0**
Total		**1802**	**680**	**330**	**709**	**84**	**1122**	**0**	**0**
Islands									
Andaman & Nicobar	State	34	0	0	0	34	34	0	0
	Private	0	0	0	0	0	0	0	0
	Center	0	0	0	0	0	0	0	0
Total		**34**	**0**	**0**	**0**	**34**	**34**	**0**	**0**
Lakshadweep	State	10	0	0	0	10	10	0	0
	Private	0	0	0	0	0	0	0	0
	Center	0	0	0	0	0	0	0	0
Total		**10**	**0**	**0**	**0**	**10**	**10**	**0**	**0**
Total Islands	**State**	**44**	**0**	**0**	**0**	**44**	**44**	**0**	**0**
	Private	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Center	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total		**44**	**0**	**0**	**0**	**44**	**44**	**0**	**0**

Most states have been experiencing power shortages as shown in the Table below.

Table 14.2.5 Power shortages (MW)

State	November, 2001				April, 2001-November, 2001			
	Peak demand	Peak Met	Shortage	%	Peak demand	Peak Met	Shortage	%
Chandigarh	140	140	0	0.0	180	180	0	0.0
Delhi	2645	2481	164	6.2	3040	2879	161	5.3
Haryana	2593	2528	65	2.5	2970	2900	70	2.4
H. P.	519	519	0	0.0	540	519	21	3.9
J & K	1179	909	270	22.9	1179	991	188	15.9
Punjab	3775	3525	250	6.6	5420	4936	484	8.9
Rajasthan	3603	3603	0	0.0	3603	3603	0	0.0
U.P.	7492	6887	605	8.1	7584	6887	697	9.2
Chattisgarh	1336	1277	59	4.4	1357	1311	46	3.4
Gujarat	7894	6498	1396	17.7	7894	6700	1194	15.1
M.P.	5313	4457	856	16.1	5313	4457	856	16.1
Maharashtra	12052	10458	1594	13.2	12200	10458	1742	14.3
Goa	259	259	0	0.0	293	293	0	0.0
A.P.	6549	5741	808	12.3	7622	6283	1339	17.6
Karnataka	4604	3985	619	13.4	5321	3985	1336	25.1
Kerala	2591	2185	406	15.7	2591	2189	402	15.5
Tamil Nadu	6682	5718	964	14.4	6900	5843	1057	15.3
Bihar	1349	1203	146	10.8	1356	1288	68	5.0
D.V.C.	1225	1124	101	8.2	1296	1209	87	6.7
Orissa	1983	1883	100	5.0	1983	1883	100	5.0
West Bengal	3499	3397	102	2.9	3614	3414	200	5.5
Arunachal Pr.	48	47	1	2.1	50	50	0	0.0
Assam	596	583	13	2.2	688	618	70	10.2
Manipur	94	94	0	0.0	98	94	4	4.1
Meghalaya	137	136	1	0.7	137	136	1	0.7
Mizoram	73	73	0	0.0	73	73	0	0.0
Nagaland	50	50	0	0.0	61	58	3	4.9
Tripura	133	113	15	15.0	156	140	16	10.3
All India	**75007**	**67498**	**7509**	**10.0**	**77956**	**67663**	**10293**	**13.2**

We do not expect any great improvement in the situation by 2006/7. We have assumed that existing shortages in energy supply will continue and have calculated the required generation capacity on that basis. To that end, we have made three assumptions discussed below:

T&D losses

The 16th EPS has assumed some improvement in T&D losses in the states as shown in the Table below.

Table 14.2.6 Improvement in T&D losses

All India and Statewise - Transmission and distribution losses (%)

State	1999-00 Estimated	2000-01	2001-02	2002-03	2003-04	2004-05
Haryana	32.8	32.6	32.2	31.8	31.4	31
Himachal Pradesh	25.3	25.2	25.1	25	24.9	24.8
Jammu & Kashmir	46.5	45.5	44.5	43.5	42.5	41.5
Punjab	18.84	18.75	18.66	18.57	18.48	18.36
Rajasthan	24.6	24.5	24.4	24.3	24.2	24.1
Uttar Pradesh	26.3	26.1	25.9	25.7	25.5	25.3
Chandigarh	30	29.5	29	28.5	28	27.5
Delhi	47.8	46.8	45.8	44.8	43.8	42.8
Goa	27.25	27	26.75	26.5	26.25	26
Gujarat	21.46	21.14	20.81	20.48	20.16	19.83
Madhya Pradesh	20.2	20.1	20	19.9	19.8	19.7
Maharashtra	16.82	16.75	16.69	16.62	16.55	16.47
Dadra & Nagar Haveli	11.2	11.1	11	10.9	10.8	10.7
Daman & Diu	8.43	8.42	8.54	8.54	8.48	8.55
Andhra Pradesh	31.1	29.6	28.1	26.1	24.1	22.1
Karnataka	18.9	18.8	18.7	18.6	18.5	18.4
Kerala	20.7	20.5	20.3	20.1	19.9	19.7
Tamil Nadu	16.9	16.81	16.71	16.63	16.55	16.65
Pondicherry	13.21	13.21	13.22	12.82	12.79	12.81
Bihar	16.21	16.25	16.31	16.39	16.48	16.53
Orissa	24.5	24	23.5	23	22.5	22
Sikkim	20	20	20	20	20	20
West Bengal	21.18	20.93	20.71	20.49	20.27	20.05
Arunachal Pradesh	29.51	28.86	28.42	28.14	27.38	27.03
Assam	23	23	22.9	22.8	22.7	22.6
Manipur	21.28	21.21	21.05	20.99	20.94	20.77
Meghalaya	26.69	26.44	26.14	25.84	25.5	25.23
Mizoram	39	37	35	33	31	29
Nagaland	34.38	33.91	33.54	32.98	31.99	31.03
Tripura	30.5	30	29.5	29	28.5	28
All India	23.14	22.83	22.53	22.14	21.77	21.41

We have assumed a further improvement of 2% in the T&D losses by 2006-07. We feel justified in making this assumption as electricity sector regulators have been appointed in most states and the regulators have put considerable stress on loss reduction.

PLF

With little additional capacity coming in, the pressure on existing plants would be high and their performance is bound to improve. This has been the experience in the nineties. We assume that the PLF of all existing plants and the new plants will improve by 5% over the level usually assumed by CEA.

Captive generation

Captive generation has increased rapidly in the nineties. Large industries account for most of captive power generation. The growth in captive generation would depend on the growth rate in industrial production and the price of power paid by the industry to the utilities. These prices are high because of the cross-subsidy between sectors. The cross-subsidies are being phased out. This should result in a reduction of power prices for the industry and therefore a reduction in captive generation. The 16th EPS has projected the growth of captive generation upto 2004/5. We have used the same growth rate to project the captive generation in 2006/7. This is shown in the Table below.

Table 14.2.7 Growth in captive generation (MKwh)

States	1999/00	2004-05	2006/07
Haryana	835	1178	1352
Himachal Pradesh	75	110	128
Jammu & Kashmir	1	1	1
Punjab	381	601	721
Rajasthan	1423	1573	1637
UP	6141	8050	8971
Chandigarh	2	2	2
Delhi	100	130	144
Goa	95	95	95
Gujarat	6766	7927	8445
Madhya Pradesh	4891	5079	5156
Maharashtra	1490	1539	1559
D & N Haveli	31	36	38
Daman & Diu	-	-	-
Andhra Pradesh	5541	6223	6519
Kamataka	2393	2731	2879
Kerala	612	793	880
Tamil Nadu	2412	2526	2573
Pondicherry	14	14	14
Bihar (excl DVC)	2935	2972	2987
Orissa	7086	12520	15721
Sikkim	-	-	-
West Bengal	1041	1451	1657
Arunachal Pradesh	-	-	-
Assam	679	698	706
Manipur	-	-	-
Meghalaya	-	-	-
Mizoram	-	-	-
Nagaland	2	2	2
Tripura	-	-	-
Andaman & Nicobar	1	1	1
Lakshadweep	0	0	0
All India	44947	56252	62189

CEA has recently drawn up a list of power projects which could be set up in the Tenth Plan (2002-07). These projects add up to a capacity of 47,000 MW. Over the last two five year plans we have added slightly less than 20,000 MW in each plan period. It is highly unlikely that 47,000MW will be added in the next five years. We have accordingly assumed that only the sanctioned and ongoing (SOG) schemes in the CEA's list will be commissioned by 2006/7.

Table 13.2.8 bring out the position in 2006/7.

Table 14.2.8 Power deficit position in 2006/7

States	Energy requirement 16th EPS 2006/07 (MU)	Existing shortages (%)	Shortages (MU)	Net after shortages (MU)	Improvement in T&D (MU)	Net Requirement (MU)	Captive (MU)	Net after captive (MU)	Energy available (State+Private) (MU)	Deficit (MU)	Energy available (Central) (MU)	Net Deficit (MU)	90% PLF (MW)	Gas d (MMC
Haryana	25750	2.8	721	25029	501	24528	1352	23177	16793	6384	3814	2570	326	1 27
Punjab	41922	2.7	1132	40790	816	39974	721	39253	32186	7067	4222	2845	361	1 41
Rajasthan	40341	3.6	1452	38889	778	38111	1637	36474	26125	10349	6182	4166	528	2 07
Uttar Pradesh	70803	14.6	10337	60466	1209	59256	8971	50286	42737	7548	4509	3039	385	1 51
Delhi	25672	4.9	1258	24414	488	23926	144	23781	19004	4777	2854	1923	244	0 95
Goa	2207	10.8	238	1969	39	1929	95	1834	1576	258	136	122	16	0 06
Gujarat	61683	9.7	5983	55700	1114	54586	8445	46140	53716	0	0	0	0	0 00
Madhya Pradesh	51952	12 4	6442	45510	910	44600	5156	39444	36577	2866	1508	1358	172	0 67
Maharashtra	106892	10.5	11224	95668	1913	93755	1559	92196	71184	21012	11053	9959	1263	4 94
Andhra Pradesh	68797	7.8	5366	63431	1269	62162	6519	55643	51857	3787	1327	2460	312	1 22
Karnataka	44748	9.1	4072	40676	814	39862	2879	36983	28786	8197	2873	5324	675	2 64
Kerala	22998	6.6	1518	21480	430	21051	880	20171	13239	6932	2430	4503	571	2 23
Tamil Nadu	54872	7.6	4170	50702	1014	49688	2573	47115	40116	6999	2453	4546	577	2 26
Bihar (excl DVC)	12256	7	858	11398	228	11170	2987	8183	8702	0	0	0	0	0 00
DVC	11129	-1.7	-189	11318	226	11092	0	11092	8510	2582	4755	0	0	0 00
Orissa	17997	-3.1	-558	18555	371	18184	15721	2463	12070	0	0	0	0	0 00
West Bengal (excl DVC)	27846	-0 9	-251	28097	562	27535	1657	25878	19115	6763	12455	0	0	0 00
Arunachal Pradesh	303	-1.9	-6	309	6	303	0	303	130	172	173	0	0	0 00
Assam	5294	-7.8	-413	5707	114	5593	706	4887	3856	1031	1031	0	0	0 00
Manipur	1039	2.3	24	1015	20	995	0	995	45304	0	0	0	0	0 00
Meghalaya	955	-7 3	-70	1025	20	1004	0	1004	605	399	399	0	0	0 00
Mizoram	525	-2.7	-14	539	11	528	0	528	309	220	220	0	0	0 00
Nagaland	388	-2.6	-10	398	8	390	2	388	336	52	52	0	0	0 00
Tripura	997	-3.9	-39	1036	21	1015	0	1015	596	419	419	0	0	0 00
Total	697366		53247	644119	12882	631237	62005	369232	533431	97813	62863	42815	5431	21 24

In 2006/7, there would be a shortfall of 42815 MU even after the SOG projects are commissioned. This could be supplied by 5431 MW of new capacity working at a PLF of 90%. It is too late now to set up coal based or hydroelectric units to meet this deficit but gas based units could still be set up and we have counted this in computing the gas demand in 2006/7.

The gas demand in 2006/7 from the power sector would have the following elements:

- Demand from existing gas based units - 42.76 MMCMD

(This is the gas allocated to these units)

- Demand from existing naphtha/diesel based units - 6.61 MMCMD
- Demand from SOG gas/naphtha (Annexure-2.2) - 1.18 MMCMD
- Demand from possible units to meet deficit (Annexure 2.3)– 21.24 MMCMD

Total demand- 71.79 MMCMD

In planning the capacity for 2006/7, we have not considered the peak load, assuming that peaking shortages would remain. Meeting these shortages would require even higher capacities to be installed and that is plainly unlikely. We have also not considered the retirement of existing plants as we believe the old plants would be covered under R&M schemes and would not be retired when new capacity is in short supply. At present, there is only a limited amount of inter-state trade in power. In calculating the statewise gas demands, we have accordingly assumed that the power required by a state would be generated within the state.

Many of our assumptions regarding T&D losses, PLF, captive generation, etc. would depend critically on the regulatory regimes in the states. One of the tasks before the regulators is to rationalise power tariffs. This would have its effect on demand although the price elasticity of demand would be low. More importantly, tariff reforms would determine the ability of SEBs to pay for power, or to enter into long term take-or-pay contracts. As yet there is considerable uncertainty on the progress of regulatory reforms. To that extent, the gas demand projections also are uncertain.

The statewise break-up of the gas demand for power generation is shown below.

Table 14.2.9 Gas demand for power generation (MMCMD)

State	2006
Northern region	
Delhi	4.38
Uttar Pradesh	6.63
Punjab	1.41
Rajasthan	5.06
Haryana	3.24
Sub Total	20.72
Western region	
Goa	0.06
Gujarat	10.56
Madhya Pradesh	0.67
Maharashtra	10.94
Sub Total	22.23
Southern region	
Andhra Pradesh	10.67
Karnataka	3.24

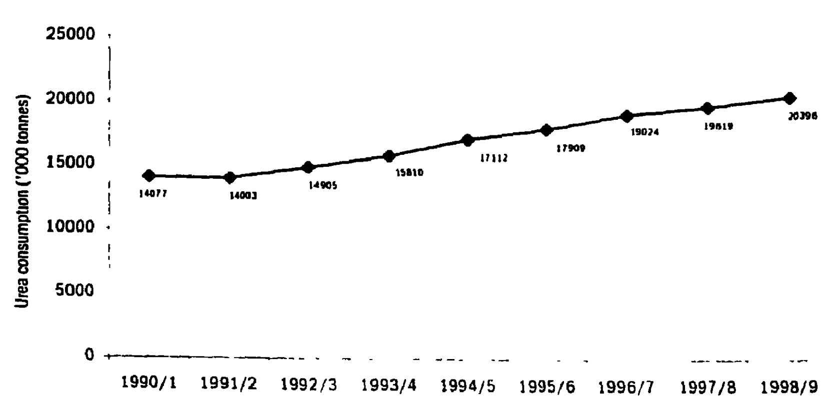
State	2006
Kerala	4.91
Tamil Nadu	6.98
Sub Total	**25.80**
Eastern region	
Orissa	0.00
West Bengal	0.05
Bihar & Jharkhand	0.00
Sub Total	0.05
North eastern region	
Arunachal Pradesh	0.06
Assam	1.10
Manipur	0.04
Meghalaya	0.01
Mizoram	0.11
Nagaland	0.01
Tripura	1.67
Sub Total	**2.99**
All India Total	71.79

Production of urea

Seventy-five per cent of the fertilizer used in India is used in the production of foodgrains, namely, rice, wheat, pulses and sugarcane. Eighty-five per cent of the nitrogen required is applied in the form of urea. The nutrients - N, P and K - are ideally used in the proportion of 5.9:2.4:1. However, since 1992, N has been applied in excess owing to the price control on urea. It is expected that this distortion would be corrected when the urea price is decontrolled. The intensity of fertilizer use in India is low at 75 kg/hectare as very little fertilizer is used in non-irrigated lands.

Urea consumption in the country has increased at an annual rate of about 5% from 14 million tonnes in 1990/91 to 20 million tonnes in 1998/99 as shown below.

Figure 14.2.1 Urea consumption in India



Source. Fertilizer Association of India

While most of the urea consumed in the country has been produced domestically, a part of the requirement has been imported. Urea consumption and imports over the past decade is in the Table below.

Table 14.2.10 Urea imports by India (1991-99)

Year	Urea consumption (million tonnes)	Urea imports (million tonnes)	Imports as % of consumption
1991-92	14.00	0.39	3
1992-93	14.91	1.86	12
1993-94	15.81	2.84	18
1994-95	17.11	2.88	17
1995-96	17.91	3.78	21
1996-97	19.02	2.33	12
1997-98	19.62	2.39	12
1998-99	20.40	0.56	3

Source. Fertilizer Association of India

Over the last two years, the consumption of urea has not shown any growth and the import has dropped to zero last year.

The import price of urea has fluctuated widely, sharply increasing whenever India and China increased their imports. The international prices since 1970 are shown in the Table below.

Table 14.2.11 International urea prices

Year	Price at current $ (per MT)	Year	Price at current $ (per MT)	Year	Price at current $ (per MT)
1971	46.00	1980	222.10	1989	132.20
1972	59.30	1981	216.00	1990	157.00
1973	94.80	1982	158.80	1991	172.00
1974	315.80	1983	135.40	1992	140.30
1975	198.00	1984	171.30	1993	106.75
1976	112.00	1985	136.30	1994	147.92
1977	127.40	1986	107.00	1995	211.50
1978	144.80	1987	116.60	1996	205.48
1979	172.90	1988	155.00	1997	103.00
				1998	91.00

Source. EPW July 1999

The long-term average cif price at Mumbai works out to $150/MT.

Urea demand projections

Fertilizer demand projections are based on projections of growth in agricultural production. The agriculture sector has faced some major problems after the economic reforms of the early nineties. The production actually decreased in

1995-96 and 1997-98. The overall growth rate in foodgrains production in the nineties was 2.7%. The Fertilizer Association of India (FAI) estimates that the foodgrain production in India in 2011/12 will reach 340 million tonnes. This implies a growth rate of 4% over 1999-2012. There is some uncertainty at present as to the impact that the WTO agreements would have on agriculture. There could be a major shift from crops grown for self-consumption to cash crops and exportable crops. However, these factors can be taken into account only after more information becomes available and we have adopted the FAI estimates of foodgrain production.

To project the fertilizer requirement in 2011-12, we assume that one ton of fertilizer increases foodgrain production by 10 tonnes. This is higher than a figure of 7.5 tonnes also adopted in some forecasts but we assume that improvements in water management expected in future would make the higher yields possible. The foodgrains production in 1998-99 was 204 million tonnes. An increase of 136 million tonnes of foodgrains would require an additional 13.6 million tonnes of all fertilizers. Assuming that foodgrains will account for 75 per cent of fertilizer consumed as at present, the total additional requirement would be 18 million tonnes in terms of N, P and K, with the additional urea requirement of 20.7 million tonnes. Adding this to the consumption of 20.4 million tonnes in 1998-99, we get a requirement of 41.1 million tonnes of urea by 2011-12.

Likely production capacity

It is, of course, not necessary to produce all the urea domestically. However, the government would like to restrict the imports on grounds of food security. Keeping imports down to the level of 20% of consumption would mean that we produce 33 million tonnes by 2012. The current production capacity is around 20 million tonnes. Pending a detailed exercise to estimate future urea demand, the government has decided not to approve any new urea plant before 2003. The proposals for four new plants with a total capacity of 3 million tonnes at Thal, Nellore, Gorakhpur and Hazira were pending for government approval at the time the ban on new capacity was imposed. These plants are likely to be cleared after 2003 and could be set up in the 2008-10 period. A joint venture project with the Oman Oil Company for a 1.5 million tonnes unit in Oman is also at an advanced stage of discussion.

However, considering time period of this study till 2006/7, we expect no new expansion plants to be commissioned within this time frame.

Choice of feedstock and potential gas demand

The oldest urea plants in the country were based on coal and fuel oil. These are now practically defunct. The plants set up in the 70's and 80's were based on naphtha. In the late 80's and the 90's, natural gas from the western offshore fields was made available through the HBJ pipeline and a number of gas based urea plants were set up.

Under the existing controlled price regime for urea, the urea producers are allowed retention prices, which compensate them fully for their capital costs and variable costs including the cost of feedstock. The urea plants based on different feedstocks do not have to compete against each other. Urea is sold on the basis of linkages decided by the government, the cost of transport from the plant to the consumption point being met by the government. A maximum price of Rs. 4,600/MT is payable by the farmers no matter where they are located.

In these circumstances, the feedstock choice is guided by availability and not the price. However, the present arrangement is proving to be costly for the government. As the average cost of production is greater than the retail price of urea, the deficit has to be met by a government subsidy. The burden of fertilizer subsidies on the budget of central government has grown dramatically over the years from Rs. 505 crores in 1980/81 to Rs. 13,244 crores in 1999/00. Driven by the need to contain the increasing subsidy, the government is considering a phased decontrol of urea prices. The Expenditure Reforms Commission has recommended a complete decontrol of the urea price by April 2006. Earlier attempts by the government to decontrol the urea price were not successful and it is not clear if the government can implement this recommendation.

Conversion from naphtha

Once the urea price is decontrolled, the urea producers will have to compete against each other and also against imports. The import of urea is now canalized but under the WTO Agreement, urea will have to be put under OGL. The domestic industry may then be protected by a suitable tariff. The government has appointed a task force to examine the feasibility of setting up new coal based urea plants. However, such plants are not expected soon. Domestic gas and LNG would be the natural choice for feedstock to the extent they are available. No new naphtha based plant is likely to be put up and the existing naphtha based plants would have to change over to gas in order to survive. Even if the urea price is not decontrolled, the government would persuade these units to change to LNG as soon as it is available in order to reduce the fertiliser subsidy.

Naphtha is now under OGL and it can be imported by anyone. Naphtha produced domestically is now sold at import parity prices. Naphtha is both imported and exported. Nearly 2 million tonnes of naphtha was exported last year. With new refinery capacity planned to be set up, the surplus of naphtha would increase. A part of this surplus naphtha may be converted into gasoline but a part of it would have to be exported. In such a situation, inland refineries in north India such as Mathura, Panipat and Bhatinda may drop their prices to export parity levels. Even then, naphtha based urea producers would find it economical to change to gas.

The existing naphtha based urea producers are listed in the Table below.

Table 14.2.12 Existing naphtha based urea units

Urea Units	State	Capacity ('000 tonnes
CFL	Andhra Pradesh	346.0
Chambal Fertilisers, Unit II	Rajasthan	775.5
Duncans Industries	Uttar Pradesh	675.0
FACT, Ambalamedu, Unit I	Kerala	330.0
HFC, Barauni	Bihar	184.0
HFC, Durgapur	West Bengal	173.0
IFFCO, Phulpur	Uttar Pradesh	1221.0
Unit I		495.0
Unit II		726.0
MFL, Manali	Tamil Nadu	486.0
MCFL, Mangalore	Karnataka	340.0
NFL, Nangal I & II	Punjab	330.0
SFC, Kota	Rajasthan	330.0
SPIC, Tuticorin	Tamil Nadu	512.0
ZIL, Zuarinagar	Goa	340.0
Naphtha based urea capacity (existing)		6042.5

Converting these units to gas would require a supply of 13.87 MMCMD. We assume these conversions can be completed by 2006/7.

Table 14.2.13 Gas demand by 2006/7

	Existing units	Conversion from naphtha	Expansion	Total
2006/07	26.35	13.87	Nil	40.22

The statewise break-up of the above demand is shown below.

Table 14.2.14 Statewise breakup of gas demand for urea production

State	2006/7
Northern region	
Punjab	0.81
Uttar Pradesh	12.82
Rajasthan	4.16
Sub Total	17.79
Western region	
Goa	0.83
Gujarat	5.51
Madhya Pradesh	3.22
Maharashtra	4.20
Sub Total	13.76
Southern region	
Andhra Pradesh	3.25
Kerala	0.81
Tamil Nadu	2.22
Karnataka	0.83
Sub Total	7.11
Eastern region	
Bihar	0.56
West Bengal	0.54
Sub Total	1.10
North eastern region	
Assam	0.45
Tripura	0.00
Sub Total	0.45
All India Total	40.22

Industry

Gas is now used by a wide variety of industrial units including sponge iron, glass and ceramics, paper, sugar, textile and chemical units. On account of the low international price of scrap iron, no new gas-based sponge iron unit has been set up in recent years. Additional capacity is coming from small coal-based units only. Accordingly, the sponge iron industry has also not been considered for calculating the gas demand. The sugar industry is not likely to take large volumes of gas as most of their fuel need is met by bagasse. Up to date data on the textile and chemical units is not available and demand from these sectors has to be established by a detailed survey. The cement industry does not at present consume any gas but this is a promising sector, which could absorb large volumes if the technology is suitably upgraded. We have accordingly computed the potential demand from the cement, paper and glass/ceramics industry.

The cement industry

The installed capacity of cement units, as of March 2000, is available from the Cement Statistics 2000 compiled by the Cement Manufacturers' Association (CMA). The total capacity of large cement plants (capacity of 2 million tonnes or more) is shown in the Table below.

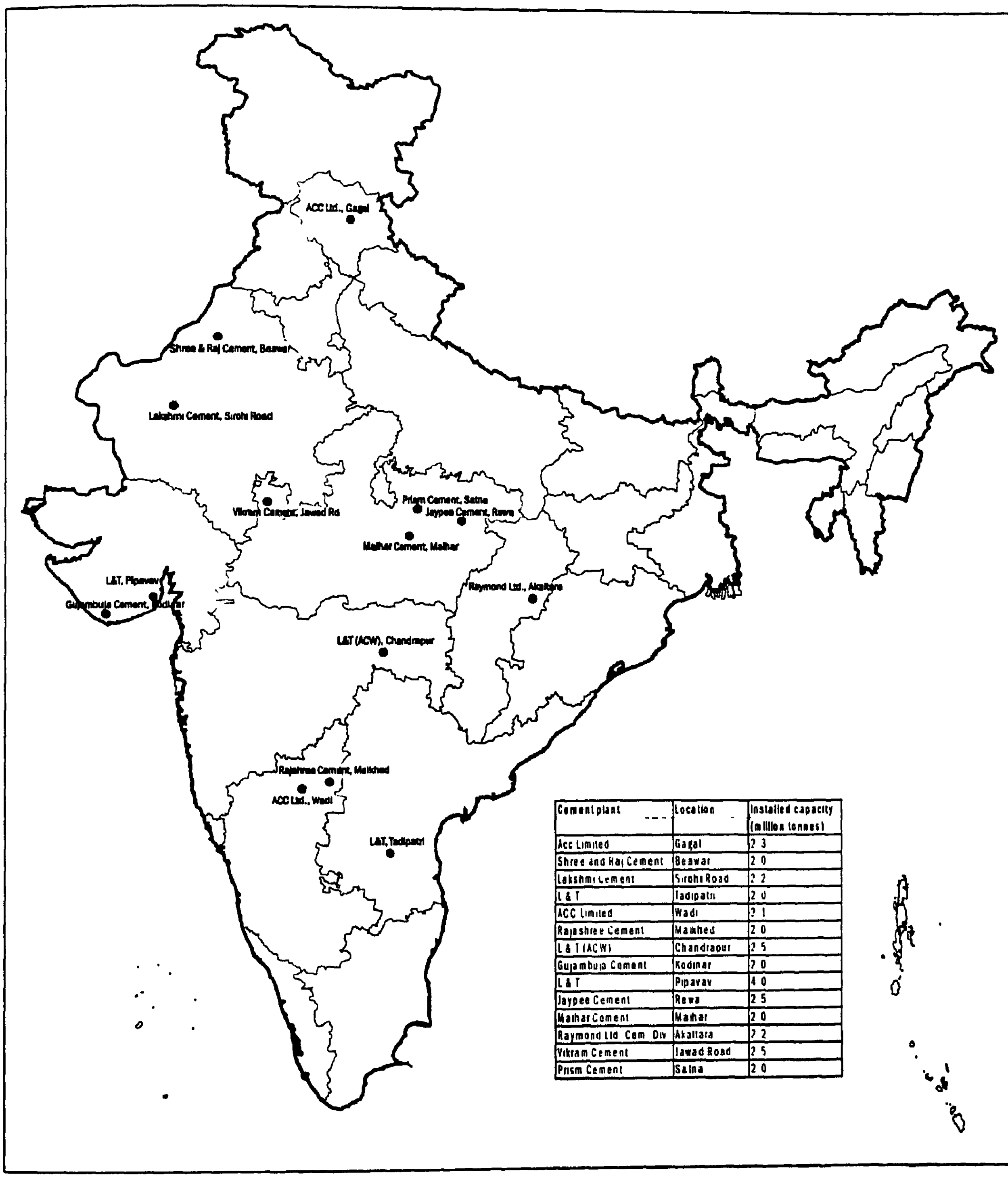
Table 14.2.15 Installed capacity of large cement units (million tonnes)

State	Installed Capacity (million tonnes)
Himachal Pradesh	2.3
Rajasthan	4.2
Gujarat	6.0
Madhya Pradesh	11.2
Maharashtra	2.5
Andhra Pradesh	2.0
Karnataka	4.1
Total	**32.3**

Source. Cement Manufacturers' Association

The cement plant clusters have been mapped as shown below.

Map 14.2.1 Cement units with installed capacity of2 million tonnes or more



Cement plant	Location	Installed capacity (million tonnes)
Acc Limited	Gagal	2 3
Shree and Raj Cement	Beawar	2 0
Lakshmi Cement	Sirohi Road	2 2
L & T	Tadipatri	2 0
ACC Limited	Wadi	2 1
Rajashree Cement	Malkhed	2 0
L & T (ACW)	Chandrapur	2 5
Gujambuja Cement	Kodinar	7 0
L & T	Pipavav	4 0
Jaypee Cement	Rewa	2 5
Maihar Cement	Maihar	2 0
Raymond Ltd Cem Div	Akaltara	7 2
Vikram Cement	Jawad Road	2 5
Prism Cement	Satna	2 0

Capacity utilization in the cement industry is about 86%. Most of the cement production in India uses the dry process. According to the CMA, the energy consumption ranges from 800 – 1060 kcals/kg of cement. An average of 930 kcals/kg has been used for evaluating the energy requirement for cement production in the states. Consequent gas demand has been estimated using a gas calorific value of 8500 kcal/m³. The plants of Madhya Pradesh have not been considered as they are too close to coalfields. Also the plant in Himachal Pradesh has not been considered as it is too remote. We have assumed a 6% growth rate in production in consultation with the industry. Only the largest units have been considered as these may change to gas more readily. The results are in the Table below.

Table 14.2.16 Estimation of gas demand for cement industry

	Unit	2000	2006
Total installed capacity in India	million tonnes	110.1	
Total cement production in India	million tonnes	94.21	
Production as a % of installed capacity	%	86	
Total capacity considered	million tonnes	18.78	
Total production considered	million tonnes	16.15	
Energy requirement for cement production	kcal/kg	930	
Total energy requirement in states	Million kcal	15020244	21306503
Calorific value of gas	kcal/m3	8500	8500
Gas demand	**MMCMD**	**4.84**	**6.87**

The statewise break-up of the above demand is shown below.

Table 14.2.17 Statewise break up of gas demand in cement industries

		Rajasthan	Gujarat	Maharashtra	Andhra Pradesh	Karnataka	Total
Total capacity considered	million tonnes	4.23	6.00	2.50	2.00	4.05	18.78
Total production considered	million tonnes	3.64	5.16	2.15	1.72	3.48	16.15
Gas demand 2000	**MMCMD**	**1.09**	**1.55**	**0.64**	**0.52**	**1.04**	**4.84**
Gas demand 2006	**MMCMD**	**1.55**	**2.19**	**0.91**	**0.73**	**1.48**	**6.87**

The paper and pulp industry

The installed capacity of paper and pulp units, as of 1998/99, is available from INPAPER Protech Directory of Indian Paper Manufacturers & Allied Industry. Installed capacities of the 10 largest units from each state have been considered and the corresponding total capacity shown below.

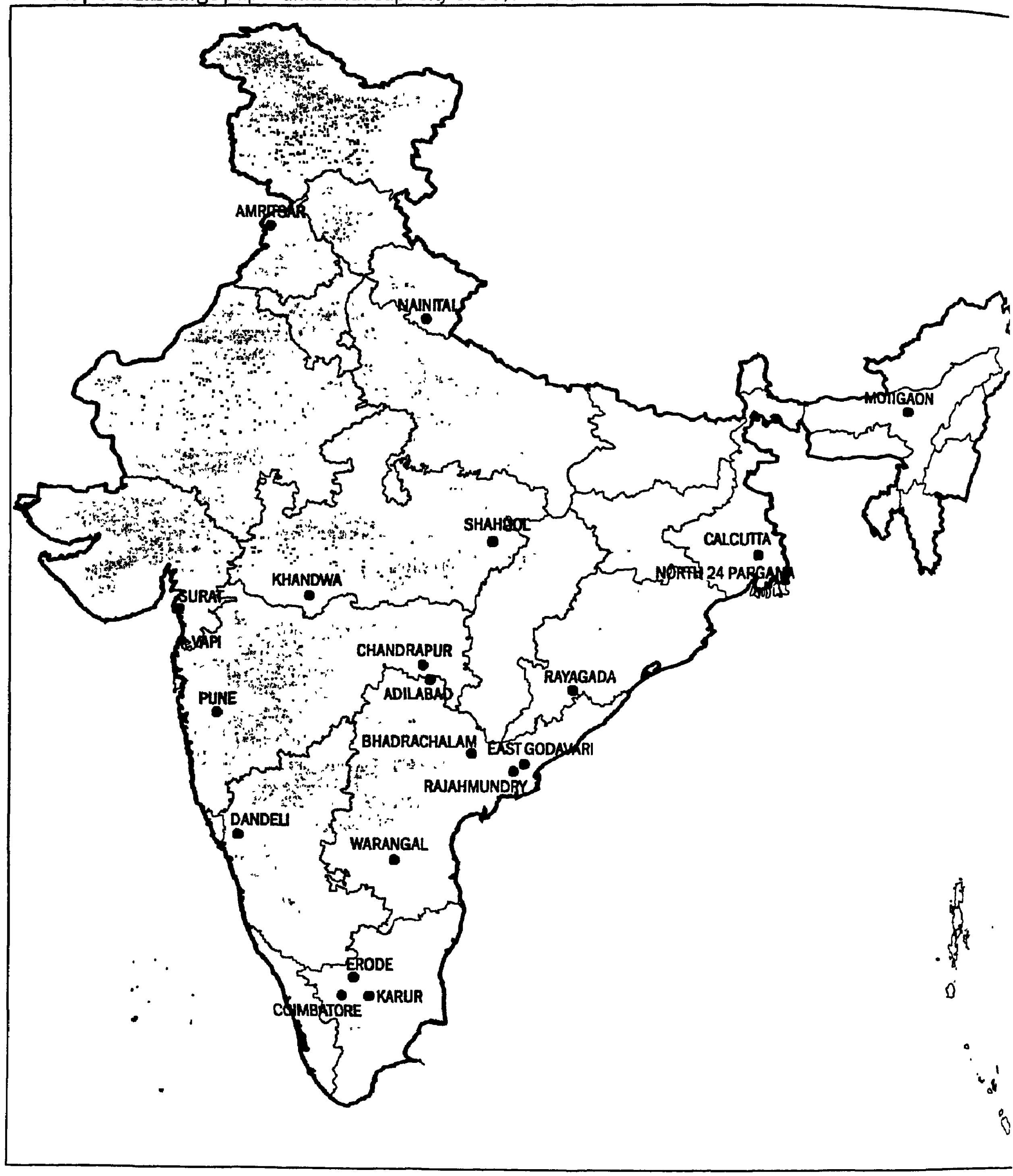
Table 14.2.18 Installed capacity of large paper and pulp units (tonnes per annum)

State	Installed Capacity
Andhra Pradesh	317500
Assam	200000
Gujarat	150000
Maharashtra	225000
Punjab	186480
Tamil Nadu	180000
Uttar Pradesh	186480
Total	**1445460**

Source. Indian Paper Manufacturers and Allied industry

The paper mill clusters (with capacities of 50,000 tonnes and above) in India have been shown in Map 14.2.2.

Map 14.2.2 Large paper units with capacity of 50,000 tonnes and above



According to industry experts, capacity utilization in the paper and pulp industry is about 70%–80%. An average of 75% has been considered for our analysis. Production has been projected to 2006/7 using an annual growth rate of 6% based on discussion with the industry. A survey done by TERI in 1995 in various states of India estimated that the average energy consumption is 9590 kcal/kg of paper production. The energy required to meet the projected production to 2006 is translated into gas demand using a calorific value of 8500 kcal per cubic metre of gas. Only the units with capacities of 100,000 tonnes per annum and above have been considered. The results are in the Table below.

Table 14.2.19 Gas demand from paper and pulp industry

	Unit	1999	2006
Total installed capacity considered	Tonnes	1445460	
Production as a % of installed capacity	%	75	
Production considered	Tonnes	1084095	
Energy requirement for cement production	kcal/kg	9590	
Total energy requirement in states	Million kcal	10396471	15632448
Calorific value of gas	kcal/m3	8500	8500
Gas demand (units >=100,000 TPA)	**MMCMD**	**3.35**	**5.04**

The statewise break-up of the above demand is shown below.

Table 14.2.20 Statewise break up of gas demand in paper and pulp industry (MMCMD)

State	1999	2006
Northern region		
Punjab	0.43	0.65
Uttar Pradesh	0.43	0.65
Sub Total	0.86	1.30
Western region		
Gujarat	0.35	0.52
Maharashtra	0.52	0.78
Sub Total	**0.87**	**1.30**
Southern region		
Andhra Pradesh	0.74	1.11
Tamil Nadu	0.42	0.63
Sub Total	**1.16**	**1.74**
North eastern region		
Assam	0.46	0.70
Sub Total	**0.46**	**0.70**
Total	**3.35**	**5.04**

Glass units

Industrial use of Liquefied Petroleum Gas (LPG) is mainly by glass units. Gas demand from the glass industry can be estimated by converting LPG consumption on calorie equivalence.

Bulk LPG sales have been projected to 2006 using an annual growth rate of 6%. The corresponding gas demand projections are shown below.

Table 14.2.21 Gas demand from glass industry

	Unit	2000	2006
Bulk LPG sales	tonnes	512870	727516
Calorific value of LPG	kcal/kg	11300	11300
Energy requirement	Million kcal	5795433	8220933
Calorific value of gas	kcal/m3	8500	8500
Gas demand	**MMCMD**	**1.87**	**2.65**

The statewise break up of gas demand in glass industries has been tabulated below.

Table 14.2.22 Statewise break up of gas demand in glass industry (MMCMD)

States	2000	2006
Northern region		
Delhi	0.32	0.45
Uttar Pradesh	0.56	0.79
Punjab	0.20	0.28
Rajasthan	0.13	0.18
Haryana	0.13	0.19
Sub Total	1.34	1.89
Western region		
Goa	0.01	0.01
Gujarat	0.13	0.19
Madhya Pradesh	0.02	0.03
Maharashtra	0.20	0.28
Sub Total	0.36	0.52
Southern region		
Andhra Pradesh	0.02	0.03
Karnataka	0.02	0.03
Kerala	0.07	0.10
Tamil Nadu	0.02	0.03
Sub Total	0.13	0.19
Eastern region		
Orissa	0.00	0.00
West Bengal	0.02	0.03
Bihar & Jharkhand	0.01	0.01
Sub Total	0.03	0.05
North eastern region		
Arunachal Pradesh	0.00	0.00
Assam	0.00	0.00
Manipur	0.00	0.00

States	2000	2006
Meghalaya	0.00	0.00
Mizoram	0.00	0.00
Nagaland	0.00	0.00
Tnpura	0.00	0.00
Sub Total	0.00	**0.01**
All India Total	1.87	**2.65**

The gas demand projections for the industrial sector as a whole is worked out in the Table below.

Table 14.2.23 Gas demand from industries (MMCMD)

Industry	Existing	2006
Cement	4.84	6.87
Paper and pulp	3.35	5.04
Glass	1.87	2.65
Total	10.06	14.56

Comments on the demand estimate

In the above analysis we have left out the textile and chemical units in the absence of reliable data. The cement industry, which has the potential of using the largest amount of gas, does not use any gas at present. Only the very large, modern units can change to gas. Even that would require efforts in introducing the technology.

Gas could be used more efficiently than alternative fuels are at present. This means equating the calorie values would overestimate the gas demand.

Unlike cement units, paper and glass units in India are already using gas but improved technology is required if these units have to use costlier imported gas.

Up to date information on industrial units is hard to come by. The gas demand from industrial units can be much better estimated through field surveys.

Captive power generation

The need for captive power generation has increased over the years. The dependence on captive power generation is the highest in the industrial sector and the main contributing factors have been the following:

- Non-availability of adequate grid supply
- Poor quality and reliability of grid supply
- High tariff as a result of heavy cross-subsidization.

Policy on captive generation

Captive capacity deprives the utilities from revenue from the sale of power. This is all the more important because non-industrial tariffs are lower than the cost of supply. Many state governments have, therefore, discouraged captive capacity. However, it has been difficult to maintain such a stand in the face of growing power shortages. The other factor favouring captive capacity is the possibility of cogeneration and using renewable sources like wind energy. The central government has recently released a policy on captive power exhorting the states to encourage captive generation. Most state governments have announced their captive power policy laying down the price payable for surplus power, wheeling charges, norms for banking of power, etc.

Installed captive capacity

Captive capacity is not reported by either the State Electricity Boards or the Central Electricity Authority. Data is available only for 1997-98 and 1998-99, compiled by Powerline Research. The publisher has explained that it is not a complete compilation and that it is based on data made available by the SEBs. The publisher estimates that unreported captive capacity could amount to as much as 40% of the capacity reported. The fuelwise break up of captive capacities in the states as reported by Powerline Research is shown in the Tables below.

Table 14.2.24 Captive capacity by fuel type in 1997-98 **(MW)**

State	Steam	Diesel	Gas/Naphtha	Hydel	Total
Andhra Pradesh	619	556	45	0	1220
Assam	NA	NA	NA	NA	NA
Bihar	523	92	0	0	614
Delhi	NA	NA	NA	NA	NA
Gujarat	391	149	965	0	1505
Haryana	70	206	60	0	335
Himachal Pradesh	0	32	0	0	32
Jammu & Kashmir	0	3	0	0	3
Karnataka	360	675	0	10	1045
Kerala	0	139	0	12	151
Madhya Pradesh	742	579	11	0	1333
Maharashtra	14	229	326	0	570
Meghalaya	NA	NA	NA	NA	NA
Orissa	1360	155	28	0	1544
Punjab	62	249	0	0	311
Rajasthan	138	345	46	0	528
Tamil Nadu	134	973	0	0	1107
Uttar Pradesh	854	90	296	0	1240
West Bengal	361	403	21	0	786
Total	5627	4874	1799	22	12322

Source. 1999 Captive Report (Powerline)

Table 14.2.25 Captive capacity by fuel type in 1998-99 (MW)

State	Steam	Diesel	Gas/Naphtha	Hydel	Other	Total
Andhra Pradesh	690	576	45	2	0	1312
Assam	65	25	219	0	0	309
Bihar	534	92	0	0	0	625
Delhi	NA	NA	NA	NA	NA	NA
Gujarat	428	256	1076	0	90	1850
Haryana	69	214	60	0	0	343
Himachal Pradesh	0	31	0	0	0	31
Jammu & Kashmir	0	3	0	0	0	3
Karnataka	552	697	0	10	0	1259
Kerala	0	164	3	12	0	178
Madhya Pradesh	800	680	11	0	4	1495
Maharashtra	60	273	330	0	45	708
Meghalaya	NA	NA	NA	NA	NA	NA
Orissa	1447	157	28	0	0	1632
Punjab	76	419	0	0	0	495
Rajasthan	162	356	46	0	9	573
Tamil Nadu	218	1596	0	0	0	1814
Uttar Pradesh	854	124	296	0	0	1275
West Bengal	361	419	21	0	0	801
Total	6317	6081	2135	24	148	14705

Source. 1999 Captive Report (Powerline)

Potential gas demand

Captive generation in 2006/7 have been projected using the growth rate projected over 1999/2000 to 2004/5 in the 16th EPS (Table 14.2.7). It has been assumed that captive gas based generators would operate as open cycle plants with an efficiency of 35%.

Captive generation based on coal and diesel is not convertible to gas but the naphtha based capacity can be converted. So far as new units are concerned, we assume that the share of steam and hydel remains the same and that all other capacity will be gas based.

With these assumptions, the gas demand works out as below:

Table 14.2.26 Gas demand for captive generation

	Unit	1999/00	2006/7
Captive generation	MU	44823	
Additional captive generation	MU		16526
Captive gas based generation	MU	7279	
Additional captive gas based generation	MU		5779
Existing gas demand (including conversion of naphtha)	MMCMD	5.78	
Additional gas demand	MMCMD		4.59
Total gas demand	MMCMD	5.78	10.36

The statewise break-up of the above demand is shown below.

Table 14.2.27 Statewise break up of gas demand for captive generation (MMCMD)

State	1999/00	2006/07
Northern region		
Haryana	0.12	0.44
Punjab	0.00	0.23
Rajasthan	0.09	0.21
Uttar Pradesh	1.13	1.87
Delhi	0.00	0.04
Sub Total	1.34	2.79
Western region		
Goa	0.08	0.08
Gujarat	3.12	4.15
Madhya Pradesh	0.03	0.13
Maharashtra	0.55	0.60
Sub Total	3.78	4.95
Southern region		
Andhra Pradesh	0.15	0.52
Karnataka	0.00	0.21
Kerala	0.01	0.21
Tamil Nadu	0.00	0.11
Sub Total	0.16	1.05
Eastern region		
Bihar	0.00	0.01
Orissa	0.10	0.87
West Bengal	0.02	0.29
Sub Total	0.12	1.17
North eastern region		
Arunachal Pradesh	0.00	0.00
Assam	0.38	0.40
Manipur	0.00	0.00
Meghalaya	0.00	0.00
Mizoram	0.00	0.00
Nagaland	0.00	0.00
Tripura	0.00	0.00
Sub Total	0.38	0.40
Total	5.78	10.36

Putting together the sectoral gas demands, we get the total demand as shown below.

Table 14.2.28 Total gas demand (MMCMD)

	Existing	2006/7
Power	49.37	71.79
Fertiliser	40.22	40.22
Industries*	10.06	14.56
Captive	5.78	10.36
Total	105.43	136.93

* Does not include industries other than cement, paper and glass.

Annexure 14.3
Imputed values

Power generation

The imputed values for power generation have been computed at the following points covering the states where gas use is considered feasible. West Bengal, Bihar and Orissa have been left out as they are coal bearing states; Himachal Pradesh and Jammu and Kashmir have not been considered as they are too remote. The locations selected are places where power projects are proposed to be set up.

Table 14.3.1 Locations for imputed values in power generation

State	Location
Delhi	Bawana
Haryana	Faridabad, Hisar
Punjab	Doraha, Bathinda, Govindwal
Rajasthan	Dholpur, Suratgarh, Anta
Gujarat	Kawas, Gandhar, Mundra, Pipavav
Uttar Pradesh	Auraiya, Unchahar, Jawaharpur, Anpara, Partapur
Madhya Pradesh	Bhander, Rosa, Sipat, Korba, Vindhyachal, Raigarh
Maharashtra	Trombay, Chandrapur
Andhra Pradesh	Vizag
Karnataka	Raichur
Tamil Nadu	Chennai
Kerala	Kayamkulam
Assam	Guwahati

Capital cost per unit of power, including interest during construction (IDC) are annuitised using the capital recovery factor which is determined by the operating life of the project and the discount/interest rates. Annual generation, determined by the plant load factor (PLF) minus the auxiliary consumption gives the net units sent out in a year. These together provide the capital cost per unit of electricity sent out which along with the O&M costs and the fuel costs per unit give the total cost of generation of a unit of electricity sent out.

Cost of coal

Supply of coal to power plant locations has been considered from Korba, Talcher and Ib valley coal fields keeping in view the future availability of coal. Coal prices have been decontrolled from January 2000. These prices are now determined by Coal India Limited (CIL). No indications from CIL are available on how the prices will move in future.

The current power grade coal price from Korba and Talcher is Rs 396/MT and Rs 351/MT respectively. Rs. 50/MT of royalty, Rs. 21 for sizing and internal

transport, Rs. 3.50/MT of excise have been added to the pithead cost to arrive at the price of coal from Korba. Estimates of coal washing charges range from Rs 150-300/MT. We have taken Rs 150/MT as the long term washing charges. Transportation costs are added to arrive at the final price of domestic coal at various power plant locations. The delivered costs of domestic coal are listed in table below.

Table 14.3.2 Delivered cost of domestic coal to selected locations

Power Plant	Coalfield	State	Distance (km)	Freight (Rs/ton)	ex-Korba prices	Delivered prices (Rs/MT)	
						washed	without washing
Dholpur	Korba	Rajasthan	967	744	449.5	1344	1215
Doraha	Korba	Punjab	1439	1068	449.5	1668	1539
Faridabad	Korba	Haryana	1175	881.9	449.5	1481	1352
Hisar	Korba	Haryana	1404	1049.5	449.5	1649	1520
Auraiya	Korba	Uttar Pradesh	998	779.8	449.5	1379	1250
Bhander	Korba	Madhya Pradesh	909	705.3	449.5	1305	1176
Bhawana	Korba	Delhi	1211	919.8	449.5	1519	1390
Kawas	Korba	Gujarat	1436	1068	449.5	1668	1539
Ghandhar	Korba	Gujarat	1351	1022.8	449.5	1622	1493
Bhatinda	Korba	Punjab	1708	1213.6	449.5	1813	1684
Suratgarh	Korba	Rajasthan	1858	1287.5	449.5	1887	1758
Anta	Korba	Rajasthan	991	761.1	449.5	1361	1232
Unchahar	Korba	Uttar Pradesh	821	629.4	449.5	1229	1100
Rosa	Korba	Madhya Pradesh	1269	957.8	449.5	1557	1428
Sipat	Korba	Madhya Pradesh	78	103.8	449.5	703	574
Korba	Korba	Madhya Pradesh	0	0	449.5	600	471
Jawaharpur	Korba	Uttar Pradesh	1030	799.6	449.5	1399	1270
Partapur	Korba	Uttar Pradesh	1687	1196.1	449.5	1796	1667
Mundra	Korba	Gujarat	1428	1068	449.5	1668	1539
Pipavav	Korba	Gujarat	1787	1246.1	449.5	1846	1717
Vindhyachal	Korba	Madhya Pradesh	768	587	449.5	1187	1058
Raigarh	Korba	Madhya Pradesh	126	128.1	449.5	728	599
Govindwal	Korba	Punjab	1496	1096.1	449.5	1696	1567
Anpara	Korba	Uttar Pradesh	648	501.6	449.5	1101	972
Raichur	Talcher	Karnataka	rail-sea-rail	1392.9	404.5	1947	1818
Chennai	Talcher	Tamil Nadu	rail-sea-rail	852.3	404.5	1407	1278
Vizag	Talcher	Andhra Pradesh	rail	486.6	404.5	1041	912

Power Plant	Coalfield	State	Distance (km)	Freight (Rs/ton)	ex-Korba prices	Delivered prices (Rs/MT)	
						washed	without washing
Trombay	Korba	Maharashtra	1248	939.4	449.5	1539	1410
Chandrapur	Korba	Maharashtra	795	610.6	449.5	1210	1081
Kayamkulam	Talcher	Kerala	rail-sea-rail	1447.3	404.5	2002	1873

Technical and financial parameters

The calorific value of domestic power grade coal is taken as 4000 kcal/kg. Power plants which are 1500 km from coal fields or beyond have to reduce the ash content to 34%. These plants have to use either washed coal or imported coal for blending. Coal washing charges are taken to be Rs 150/MT. Washing improves the calorific value of domestic coal, which increases to 4482 kcal/kg. Blending has not been considered as an option in view of the current high price of imported coal.

NTPC is planning a 660 MW supercritical coal power plant at Seepat by 2006-07. However, till date India has operated only subcritical coal based power plants. Accordingly, in this analysis only subcritical coal power plants have been considered. A typical subcritical coal based power plant has an efficiency of about 37%. The efficiency of an advanced combined cycle gas based power plant has been taken as 56%. The technical and financial parameters of subcritical coal based plants and advanced class combined cycle gas turbines are given in Tables below.

Table 14.3.3 Technical and financial parameters for subcritical coal based plants

Technical parameters	Units	Value
Plant load factor	%	75
Auxiliary consumption (indigenous coal)	%	8.0
Life of plant	Years	30
Calorific value (indigenous coal)	kcal/kg	4000
Calorific value (washed coal)	kcal/kg	4482
Heat rate per unit sent out (indigenous coal)	kcal/kWh	2526
Financial parameters		
Discount rate	%	12
Capital cost per MW (indigenous coal based)	Rs. Million	40
Fixed operation cost as % of capital cost	%	2.5
Investment period	Years	4

Table 14.3.4 Technical and financial parameters for advanced class combined cycle gas turbines

Technical parameters	Units	Value
Plant load factor	%	80
Auxiliary consumption	%	3
Life of plant	Years	30
Calorific value	Kcal/Nm^3	8500
Heat rate per unit sent out	Kcal/kWh	1583
Financial parameters		
Discount rate	%	12
Capital cost per MW	Rs. Million	30
Fixed operation cost as % of capital cost	%	2.0
Investment period	Years	3

Imputed values of gas in power generation

The imputed values at the selected power plant locations have been given in the Table below.

Table 14.3.5 Imputed values of gas in power generation

Location	Domestic coal*
Bawana	4.70
Faridabad	4.62
Hisar	4.99
Doraha	5.03
Bhatinda	5.20
Govindwal	5.09
Dholpur	4.32
Suratgarh	5.35
Anta	4.36
Kawas	5.03
Ghandhar	4.93
Mundra	5.03
Pipavav	5.26
Auraiya	4.40
Unchahar	4.07
Jawaharpur	4.44
Anpara	3.79
Partapur	5.17
Bhander	4.23
Rosa	4.79
Sipat	2.92
Korba	2.97
Vindhyachal	3.98
Raigarh	2.97
Trombay	4.75
Chandrapur	4.03
Vizag	3.66
Raichur	5.46
Chennai	4.41
Kayamkulam	5.57
Guwahati	4.78

The calculations for the highest and lowest imputed values are at Tables 14.3.6 and 14.3. 7.

Table 14.3.6 Imputed value of gas for power generation at Sipat

Element	Unit	Gas CCGT	Domestic coal washed	Domestic coal without washing
Capital cost	Rs.million/MW	30	40	40
PLF		80%	75%	75%
Annual output (gross)	MWh	7008	6570	6570
Auxiliary consumption	(%)	3.0%	8.0%	8.0%
Units sent out/annum (net)	MWh	6798	6044	6044
Phasing of investment				
Year -3		0	0.2	0.2
Year -2		0.2	0.3	0.3
Year -1		0.5	0.4	0.4
Year -0		0.3	0.1	0.1
Total		1	1	1
Discount factor		0.12	0.12	0.12
NPV factor		1.18	1.28	1.28
Capital cost (incld IDC)	Rs.million/MW	35.27	51.02	51.02
Life of plant	Years	30	30	30
CRF		0.12	0.12	0.12
Annutised capital cost	Rs.million/MW	4.38	6.33	6.33
Capital cost/kWh of power	Rs./kWh	0.64	1.05	1.05
Heat rate per unit sent out	kcal/kWh	1583	2526	2526
Heat rate per unit sent out	Btu/kWh	6282	10025	10025
Fuel consumption/kWh sent out	NM^3, kg/kWh	0.19	0.56	0.63
Fuel cost	Rs/t		703	574
Fuel calorific value	kcal/NM^3, kcal/kg	8500	4482	4000
Fuel cost/kWh sent out	Rs/kWh		0.40	0.36
Fixed operating cost as % of capital cost	(%)	2%	2.5%	2.5%
Total fixed operating cost	Rs. million	0.600	1.000	1.000
Fixed operating cost/ kWh sent out	Rs/kWh	0.088	0.165	0.165
Capital+Fixed O&M cost/kWh sent out	Rs/kWh	0.732	1.213	1.213
Total cost per kWh sent out	Rs/kWh		1.61	1.58
Total cost per kWh sent out	$/kWh		0.035	0.034
Imputed fuel charge	Rs/kWh		0.877	0.844
Imputed fuel charge	$/kWh		0.019	0.018
Imputed value for gas	**$/MMBtu**		**3.04**	**2.92**

Table.14.3.7 Imputed value of gas for power generation at Kayamkulam

Element	Unit	Gas CCGT	Domestic coal washed	Domestic coal without washing
Capital cost	Rs.million/MW	30	40	40
PLF		80%	75%	75%
Annual output (gross)	MWh	7008	6570	6570
Auxiliary consumption	(%)	3.0%	8.0%	8.0%
Units sent out/annum (net)	MWh	6798	6044	6044
Phasing of investment				
Year -3		0	0.2	0.2
Year -2		0.2	0.3	0.3
Year -1		0.5	0.4	0.4
Year -0		0.3	0.1	0.1
Total		1	1	1
Discount factor		0.12	0.12	0.12
NPV factor		1.18	1.28	1.28
Capital cost (incld IDC)	Rs.million/MW	35.27	51.02	51.02
Life of plant	Years	30	30	30
CRF		0.12	0.12	0.12
Annutised capital cost	Rs.million/MW	4.38	6.33	6.33
Capital cost/kWh of power	Rs./kWh	0.64	1.05	1.05
Heat rate per unit sent out	kcal/kWh	1583	2526	2526
Heat rate per unit sent out	Btu/kWh	6282	10025	10025
Fuel consumption/kWh sent out	NM^3, kg/kWh	0.19	0.56	0.63
Fuel cost	Rs/t		2002	1873
Fuel calorific value	kcal/NM^3, kcal/kg	8500	4482	4000
Fuel cost/kWh sent out	Rs/kWh		1.13	1.18
Fixed operating cost as % of capital cost	(%)	2%	2.5%	2.5%
Total fixed operating cost	Rs. million	0.600	1.000	1.000
Fixed operating cost/ kWh sent out	Rs/kWh	0.088	0.165	0.165
Capital+Fixed O&M cost/kWh sent out	Rs/kWh	0.732	1.213	1.213
Total cost per kWh sent out	Rs/kWh		2.34	2.40
Total cost per kWh sent out	$/kWh		0.051	0.052
Imputed fuel charge	Rs/kWh		1.609	1.664
Imputed fuel charge	$/kWh		0.035	0.036
Imputed value for gas	**$/MMBtu**		**5.57**	**5.76**

Urea production

Imputed values of gas in urea production have been calculated at the locations as given in the Table below. Imputed values have been estimated against imported urea. The imputed value against the urea price of Rs 7500/MT recommended by the Expenditure Reforms Commission has also been computed.

Table 14.3.8 Locations for imputed values in urea production

State	Location
Rajasthan	Kota
Uttar Pradesh	Panki, Gorakhpur, Shahjahanpur, Phulpur, Jagdishpur, Babrala
Gujarat	Hazira
Punjab	Nangal
Maharashtra	Thal
West Bengal	Durgapur
Bihar	Barauni
Andhra Pradesh	Nellore, Kakinada, Vizag
Tamil Nadu	Chennai, Tuticorin
Kerala	Kochi
Karnataka	Mangalore
Goa	Goa

Currently, there is no import duty on urea. However, imputed values have been calculated assuming a 25% import duty.

Technical and financial parameters

The technical and financial parameters of gas based urea plants as given in the Table below conform to the assumptions of the High Powered Committee on Fertilizer Pricing Policy. The capital cost of new a gas based urea plant is Rs 17,000 million and that of a new naphtha based plant is Rs. 17,500 million. The capital cost of a urea plant converting from naphtha to gas has been taken at a depreciated value of Rs 8,750 million. The technical and financial parameters of a naphtha based urea plant are listed in the Table below.

Table 14. 3.9 Technical and financial parameters of a typical gas based urea plant

Technical parameters	Unit	Value
Urea capacity	Tons/year	726,000
Energy required per ton of urea	Gcal/ton	5.40
Calorific value of gas	Kcal/Nm^3	8500
Life of plant	Years	15
Financial parameters		
Discount rate	%	12
Capital cost (new plant)	Rs. Million	17,000
Capital cost (expansion plan)	Rs. Million	15,000
Fixed operating cost	Rs/ton	854
Investment period	Years	3

Table 14.3.10 Technical and financial parameters of a typical naphtha based urea plant

Technical parameters	Unit	Value
Urea capacity	Tons/year	726,000
Energy required per ton of urea	Gcal/ton	5.10
Calorific value of gas	Kcal/Nm^3	10560
Life of plant	Years	15
Financial parameters		
Discount rate	%	12
Capital cost (new plant)	Rs. Million	17,500
Fixed operating cost	Rs/ton	924
Investment period	Years	3

Price of urea

The cif price of imported urea has fluctuated widely in the past depending critically on purchases made by India and China. The international urea prices from 1971 to 1998 are given in Table 14.2.11 in Annexure 14.2.

A cif price of $150/MT is taken as the average. The landed cost of imported urea at the Indian port with a cif price of $ 150/MT, an exchange rate of Rs 46 per US dollar and 25% import duty, the landed cost at the Indian port would be Rs 8625/MT.

Imputed values of gas in urea production

Expansions of gas based urea plants have been considered at ten locations: Babrala, Jagdishpur, Shahjahanpur, Gorakhpur, Hazira, Thal, Nellore, Goa, Kochi and Kakinada. The possibility of conversion of naphtha based plant to a gas based plant is taken at the following locations: Kota, Panki, Phulpur, Vizag, Kochi, Barauni, Durgapur, Manali, Mangalore, Nangal, Tuticorin and Zuarinagar.

Imputed values of gas against urea imports are given in Table 14.3.11.

Table 14.3.11 Imputed values of gas against urea imports at $150/MT and import duty of 25%

Element	Unit	Gas based urea plant	
		New	Expansion
Urea Capacity	Tons/Year	726000	726000
Capital Cost	Rs Million	17000	15000
Phasing of investment			
Year-2		0.2	0.2
Year-1		0.5	0.5
Year-0		0.3	0.3
Total		1	1
Discount factor	.	0.12	0.12
NPV factor		1.18	1.18
Capital cost (incld IDC)	Rs.million	19986	17635
Life of plant	Years	15	15
CRF		0.15	0.15
Annutised capital cost	Rs.million	2934	2589
Capital cost/Ton of urea	Rs./Ton	4042	3566
Fuel calorific value	kcal/NM^3	8500	8500
Energy required per ton of urea	Gcal/Ton	5.40	5.40
Fuel consumption/Ton of Urea	NM^3/Ton	635	635
Fixed operating cost	Rs/Ton	854	854
Capital+Fixed O&M cost/Ton of Urea	Rs/Ton	4896	4420
1. Babrala			
Rail distance from Kandla	kms	1284	1284
Rail freight	Rs/T	715	715
cif price of urea	Rs/T	150	150

Element	Unit	Gas based urea plant	
		New	Expansion
Delivered prices	Rs/T	9340	9340
Imputed value of gas	$/T	96.6	106.9
Imputed value of gas	$/MMBtu	4.51	4.99
2. Jagdishpur			
Rail distance from Kandla	kms	1557	1557
Rail freight	Rs/T	850	850
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	9475	9475
Imputed value of gas	$/T	99.5	109.9
Imputed value of gas	$/MMBtu	4.65	5.13
3. Shahjahanpur			
Rail distance from Kandla	kms	1745	1745
Rail freight	Rs/T	913	913
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	9538	9538
Imputed value of gas	$/T	100.9	111.3
Imputed value of gas	$/MMBtu	4.71	5.19
4. Gorakhpur			
Rail distance from Kandla	kms	1711	1711
Rail freight	Rs/T	905	905
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	9530	9530
Imputed value of gas	$/T	100.7	111.1
Imputed value of gas	$/MMBtu	4.70	5.18
5. Port locations*			
Rail distance from ports	kms	0	0
Rail freight	Rs/T	0	0
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	8625	8625
Imputed value of gas	$/T	81.1	91.4
Imputed value of gas	$/MMBtu	3.78	4.27
6. Nangal			
Rail distance from Kandla	kms	1235	1235
Rail freight	Rs/T	696	696
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	9320.7	9320.7
Imputed value of gas	$/T	96.2	106.5
Imputed value of gas	$/MMBtu	4.49	4.97
7. Thal			
Rail distance from Bombay	kms	0	0
Rail freight	Rs/T	80	80
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	8705.4	8705.4
Imputed value of gas	$/T	82.8	93.2

Element	Unit	Gas based urea plant	
		New	Expansion
Imputed value of gas	$/MMBtu	3.86	4.35
8. Kota			
Rail distance from Kandla	kms	833	833
Rail freight	Rs/T	483	483
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	9107.7	9107.7
Imputed value of gas	$/T	91.6	101.9
Imputed value of gas	$/MMBtu	4.27	4.76
9. Panki			
Rail distance from Kandla	kms	1431	1431
Rail freight	Rs/T	790	790
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	9415	9415
Imputed value of gas	$/T	98.2	108.6
Imputed value of gas	$/MMBtu	4.58	5.07
10. Phulpur			
Rail distance from Kandla	kms	1595	1595
Rail freight	Rs/T	852	852
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	9477	9477
Imputed value of gas	$/T	99.6	109.9
Imputed value of gas	$/MMBtu	4.65	5.13
11. Barauni			
Rail distance from Haldia	kms	525	525
Rail freight	Rs/T	306	306
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	8930.8	8930.8
Imputed value of gas	$/T	87.7	98.1
Imputed value of gas	$/MMBtu	4.09	4.58
12. Durgapur			
Rail distance from Haldia	kms	17	17
Rail freight	Rs/T	80	80
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	8705.4	8705.4
Imputed value of gas	$/T	82.8	93.2
Imputed value of gas	$/MMBtu	3.86	4.35
13. Nellore			
Rail distance from Kakinada	kms	440	440
Rail freight	Rs/T	254	254
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	8879.4	8879.4
Imputed value of gas	$/T	86.6	96.9
Imputed value of gas	$/MMBtu	4.04	4.52

Element	Unit	Gas based urea plant	
		New	Expansion

* Port locations. Hazira, Goa, Kochi, Kakinada, Vizag, Chennai, Mangalore and Tuticorin

The Expenditure Reforms Commission has recommended that Rs 1,900/MT be allowed as concession to new units based on LNG while the farmgate price paid by the consumer is pegged at Rs 7000/ MT. In that case, the producer would receive a net price of Rs. 8,600/MT after deducting Rs 300/ MT as the marketing cost. The imputed value of gas against this producer price is $ 4.24/MMBtu for an expansion of a gas based plant and $4.85/MMBtu for conversion of naphtha based plant to a gas based plant. Details of imputed values against a producer price of Rs 8,600/MT are presented at Table below.

Table 14.3.12 Maximum price payable for gas if producer receives Rs 8,900/MT

Element	Unit	Gas based urea plant			Naphtha to gas based
		New	Half depreciated	Expansion	Conversion
Urea Capacity	Tons/Year	726000	726000	726000	726000
Capital Cost (new plants)	Rs Million	17000	8500	15000	8750
Phasing of investment					
Year-2		0.2	0.2	0.2	0.2
Year-1		0.5	0.5	0.5	0.5
Year-0		0.3	0.3	0.3	0.3
Total		1	1	1	1
Discount factor		0.12	0.12	0.12	0.12
NPV factor		1.18	1.18	1.18	1.18
Capital cost (incld IDC)	Rs.million	19986	9993	17635	10287
Life of plant	Years	15	8	15	8
CRF		0.15	0.20	0.15	0.21
Annutised capital cost	Rs.million	2934	2012	2589	2156
Capital cost/Ton of urea	Rs./Ton	4042	2771	3566	2970
Fuel calorific value	kcal/NM^3	8500	8500	8500	8500
Energy required per ton of urea	Gcal/Ton	5.40	5.40	5.40	5.40
Fuel consumption/Ton of Urea	NM^3/Ton	635	635	635	635
Fixed operating cost	Rs/Ton	854	854	854	854
Capital+Fixed O&M cost/Ton of Urea	Rs/Ton	4896	3625	4420	3824
Price of urea received by producer	Rs/T	8600	8600	8600	8600
Maximum price payable for gas/Ton of urea	Rs/T	3704	4975	4180	4776
Maximum price payable for gas	**$/MMBtu**	**3.76**	**5.05**	**4.24**	**4.85**

LNG vs Naphtha

Any urea producer wishing to change over to LNG would have to enter into a long-term contact (15-20 years) with LNG suppliers. In a situation of naphtha surplus in the country, the question remains if future naphtha prices could drop

to such low levels as to become competitive with the LNG option. If such were the case, urea producers should stay with naphtha rather than opting for LNG. To examine such possibility, we have calculated naphtha export parity prices at three locations: Kota, Panki and Phulpur. At each location, naphtha prices have been calculated corresponding to 22 $/bbl Middle East crude oil prices. The fob-Middle East naphtha prices have been regressed against fob-Middle East crude oil prices over March 1996 to June 2000. Transportation charges of 10$/MT have been added to arrive at naphtha prices at Kandla port. Refinery gate prices at Mathura are obtained by deducting 46.4 $/MT as the freight from port to refinery. Finally, naphtha export parity prices at Kota, Panki and Phulpur are arrived at by adding inland transportation. These are presented in the Table below. For comparison, naphtha import parity prices have also been evaluated and are given below. There are no customs and countervailing duty for naphtha imports in the fertilizer industry.

Table 14.3.13 Naphtha export parity prices

Parameter	Unit	Kota	Panki	Phulpur
At Crude price	$/bbl	22	22	22
AG crude price	$/bbl	24.2	24.2	24.2
AG naphtha price	$/bbl	223.0	223.0	223.0
Freight: AG to Kandla	$/T	10.0	10.0	10.0
Naphtha price at Kandla	$/T	233.0	233.0	233.0
Freight: Kandla to Mathura	$/T	46.4	46.4	46.4
Mathura: Refinery gate prices	$/T	186.6	186.6	186.6
Freight	$/T	13.6	11.7	21.1
Naphtha export parity	$/T	200.2	198.3	207.7

Table 14.3.14 Naphtha Import Parity Price at $22/bbl Middle East Crude Price

Element	Unit	EX-AG
Fob	$/MT	223
Fob	Rs/MT	10258
Load Port Charges @ 1$/MT	$/MT	46
Freight	Rs/MT	506
Cost & freight	Rs/MT	10810
Insurance @0.3%	Rs/MT	32
Ocean Loss @ 0.3%	Rs/MT	32
Cif	Rs/MT	10875
LC Charges @ 0.3% of cif	Rs/MT	33
Landing charges @ 1% of cif	Rs/MT	109
CIF + Landing charges+ LC charges	Rs/MT	11016
Customs duty	%	0%
Customs duty	Rs/MT	0
Cost + Basic Customs	Rs/MT	11016
CVD	%	0%
CVD	Rs/MT	0
Cost incl. Duty	Rs/MT	11016

Element	Unit	EX-AG
Port dues and other expenditure	Rs/MT	370
Landed Cost	Rs/MT	11386
Freight		
Haldia - Panki	Rs/MT	2074
Haldia - Phulpur	Rs/MT	1785
Kandla - Kota	Rs/MT	1563
Import Parity Price		
Panki	Rs/MT	13460
Phulpur	Rs/MT	13171
Kota	Rs/MT	12949
Panki	$/T	293
Phulpur	$/T	286
Kota	$/T	281

Calculation of the imputed values of gas against the above naphtha prices at Kota, Panki and Phulpur are presented in the Table below.

Table 14.3.15 Imputed values for urea production against naphtha export parity price

Element	Unit	Gas	Naphtha
			At crude price 22 $/bbl
Urea Capacity	Tons/Year	726000	726000
Capital Cost	Rs Million	17000	17500
Phasing of investment			
Year -2		0.2	0.2
Year -1		0.5	0.5
Year -0		0.3	0.3
Total		1	1
Discount factor		0.12	0.12
NPV factor		1.18	1.18
Capital cost (incld IDC)	Rs.million	19986	20574
Life of plant	Years	15	15
CRF		0.15	0.15
Annutised capital cost	Rs.million	2934	3021
Capital cost/Ton of urea	Rs./Ton	4042	4161
Fuel calorific value	kcal/NM^3, kcal/kg	8500	10560
Energy required per ton of urea	Gcal/Ton	5.40	5.10
Fuel consumption/Ton of Urea	NM^3, kg/Ton	635	483
Fixed operating cost	Rs/Ton	854	924
Capital+Fixed O&M cost/Ton of Urea	Rs/Ton	4896	5085
Fuel cost	Rs/t		
Kota			9207
Panki			9120
Phulpur			9552
Fuel cost/Ton of urea at	Rs/Ton		
Kota			4447
Panki			4404
Phulpur			4613
Total cost per ton of urea at	Rs/Ton		
Kota			9531

Element	Unit	Gas	Naphtha
			At crude pnce 22 $/bbl
Panki			9489
Phulpur			9698
Imputed fuel charge at	**Rs/Ton**		
Kota			**4636**
Panki			**4593**
Phulpur			**4802**
Imputed value for gas at	**$/MMBtu**		
Kota			**4.70**
Panki			**4.66**
Phulpur			**4.87**

Table 14.3.16 Imputed values for urea production against naphtha import parity

Element	Unit	Gas	Naphtha
			At crude pnce 22 $/bbl
Urea Capacity	Tons/Year	726000	726000
Capital Cost	Rs Million	17000	17500
Phasing of investment			
Year-2		0.2	0.2
Year-1		0.5	0.5
Year-0		0.3	0.3
Total		1	1
Discount factor		0.12	0.12
NPV factor		1.18	1.18
Capital cost (incld IDC)	Rs.million	19986	20574
Life of plant	Years	15	15
CRF		0.15	0.15
Annutised capital cost	Rs.million	2934	3021
Capital cost/Ton of urea	Rs./Ton	4042	4161
Fuel calorific value	Kcal/NM^3, kcal/kg	8500	10560
Energy required per ton of urea	Gcal/Ton	5.40	5.10
Fuel consumption/Ton of Urea	NM^3, kg/Ton	635	483
Fixed operating cost	Rs/Ton	854	924
Capital+Fixed O&M cost/Ton of Urea	Rs/Ton	4896	5085
Fuel cost at	Rs/t		
Kota			12949
Panki			13460
Phulpur			13171
Fuel cost/Ton of urea at	Rs/Ton		
Kota			6254
Panki			6500
Phulpur			6361
Total cost per ton of urea at	Rs/Ton		
Kota			11338
Panki			11585
Phulpur			11446
Imputed fuel charge at	Rs/Ton		
Kota			6443
Panki			6689

Element	Unit	Gas	Naphtha
			At crude price 22 $/bbl
Phulpur			6550
Imputed value for gas at	$/MMBtu		
Kota			6.54
Panki			6.79
Phulpur			6.64

Industries and captive generation

Imputed values for cement and paper industry have been calculated at the identified clusters against domestic coal.

For the glass industry, imputed values have been calculated against LPG ex-Koyali, Mathura, Mumbai and Vizag. The price of LPG has been taken at the refinery gate, the cost of movement to various locations has been omitted. For captive generation, imputed values have been calculated against naphtha ex-Koyali, Mathura, Mumbai and Vizag. Once again only the refinery gate price has been taken. If we add the transport cost of LPG and naphtha from the refinery to the actual locations, the imputed values would be larger.

Fuel costs

LPG and Naphtha

These fuels are priced on import parity basis. The 2000/01 average of fob-Middle East LPG and naphtha prices reported by Petroleum Argus have been taken. The insurance, sea freight charges, import duties and port storage and handling charges are added to the fob price to derive the landed cost of LPG and naphtha at Kandla, Mumbai and Vizag ports. The customs and countervailing duties have been taken at current rates.

Domestic coal

Average calorific value of domestic coal for industrial use is assumed to be 4,800 kcal/kg. Supplies from Korba coalfield in Madhya Pradesh have been considered. The price of D grade coal from Korba field is Rs 750/MT. Royalty of Rs 70/MT and Rs 3.50/MT of excise have been added to get the final price at Korba.

Imputed values of gas in industries and captive

Imputed values of gas for industries and captive generation have been computed on calorie equivalence. The Tables below presents calculations for the imputed values.

Table 14. 3.17 Imputed values of gas for Cement and Paper industries against domestic coal from Korba

Element	Unit	Value
Imputed values of gas at Sikka		
Domestic coal price	Rs /Ton	2061.9
Calorific Value: Domestic coal	Kcal/Kg	4800
Coal price	Rs/Kcal	0.0004
Calorific Value:LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	3.65
Imputed value	$/MMBtu	2.35
Imputed values of gas at Kota		
Element	Unit	Value
Domestic coal price	Rs /Ton	1567.5
Calorific Value: Domestic coal	Kcal/Kg	4800
Coal price	Rs/Kcal	0.0003
Calorific Value:LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	2.78
Imputed value	$/MMBtu	1.79
Imputed values of gas at Delhi		
Element	Unit	Value
Domestic coal price	Rs /Ton	1743.3
Calorific Value: Domestic coal	Kcal/Kg	4800
Coal price	Rs/Kcal	0.0004
Calorific Value:LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	3.09
Imputed value	$/MMBtu	1.99
Imputed values of gas at Pipavav		
Element	Unit	Value
Domestic coal price	Rs /Ton	2069.6
Calorific Value: Domestic coal	Kcal/Kg	4800
Coal price	Rs/Kcal	0.0004
Calorific Value:LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	3.66
Imputed value	$/MMBtu	2.36
Imputed values of gas at Satna		
Element	Unit	Value
Domestic coal price	Rs /Ton	1191.7
Calorific Value: Domestic coal	Kcal/Kg	4800
Coal price	Rs/Kcal	0.0002
Calorific Value:LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	2.11
Imputed value	$/MMBtu	1.36
Imputed values of gas at Surat		
Element	Unit	Value
Domestic coal price	Rs /Ton	1891.5
Calorific Value: Domestic coal	Kcal/Kg	4800
Coal price	Rs/Kcal	0.0004
Calorific Value:LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	3.35
Imputed value	$/MMBtu	2.16
Imputed values of gas at Amritsar		
Element	Unit	Value
Domestic coal price	Rs /Ton	1962.9

Element	Unit	Value
Calonfic Value: Domestic coal	Kcal/Kg	4800
Coal pnce	Rs/Kcal	0.0004
Calonfic Value:LNG	Kcal/m3	8500
Equivalent gas pnce	Rs/m3	3.48
Imputed value	**$/MMBtu**	**2.24**

Imputed values of gas at Chandrapur

Element	Unit	Value
Domestic coal pnce	Rs /Ton	1434.1
Calonfic Value. Domestic coal	Kcal/Kg	4800
Coal pnce	Rs/Kcal	0.0003
Calonfic Value LNG	Kcal/m3	8500
Equivalent gas pnce	Rs/m3	2.54
Imputed value	**$/MMBtu**	**1.64**

Imputed values of gas at Tadpatri

Element	Unit	Value
Domestic coal pnce	Rs /Ton	1919.6
Calonfic Value. Domestic coal	Kcal/Kg	4800
Coal pnce	Rs/Kcal	0.0004
Calonfic Value.LNG	Kcal/m3	8500
Equivalent gas pnce	Rs/m3	3.40
Imputed value	**$/MMBtu**	**2.19**

Imputed values of gas at Malkhed

Element	Unit	Value
Domestic coal pnce	Rs /Ton	1762.9
Calonfic Value: Domestic coal	Kcal/Kg	4800
Coal pnce	Rs/Kcal	0.0004
Calonfic Value.LNG	Kcal/m3	8500
Equivalent gas pnce	Rs/m3	3.12
Imputed value	**$/MMBtu**	**2.01**

Table 14.3.18 Imputed values of gas for glass industries against LPG

Element	Unit	Value
Ex-Koyali prices		
LPG price	Rs /Ton	20829
Calorific Value: LPG	Kcal/Kg	11300
LPG price	Rs/Kcal	0.0018
Calorific Value: LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	15.67
Imputed value	**$/MMBtu**	**10.10**
Ex-Mathura prices		
Element	**Unit**	**Value**
LPG price	Rs /Ton	21781
Calorific Value: LPG	Kcal/Kg	11300
LPG price	Rs/Kcal	0.0019
Calorific Value: LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	16.38
Imputed value	**$/MMBtu**	**10.56**
Ex-Mumbai prices		
Element	**Unit**	**Value**
LPG price	Rs /Ton	20477
Calorific Value: LPG	Kcal/Kg	11300
LPG price	Rs/Kcal	0.0018
Calorific Value: LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	15.40
Imputed value	**$/MMBtu**	**9.93**
Ex-Vizag prices		
Element	**Unit**	**Value**
LPG price	Rs /Ton	20210
Calorific Value: LPG	Kcal/Kg	11300
LPG price	Rs/Kcal	0.0018
Calorific Value: LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	15.20
Imputed value	**$/MMBtu**	**9.80**

Table 14.3.19 Imputed values of gas for captive generation against naphtha

Element	Unit	Value
Ex-Koyali prices		
Naphtha price	Rs /Ton	14060
Calorific Value:naphtha	Kcal/Kg	10560
Naphtha price	Rs/Kcal	0.0013
Calorific Value: LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	11.32
Imputed value	**$/MMBtu**	7.29

Ex-Mathura prices		
Element	**Unit**	**Value**
Naphtha price	Rs /Ton	15212
Calorific Value:naphtha	Kcal/Kg	10560
Naphtha price	Rs/Kcal	0.0014
Calorific Value: LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	12.24
Imputed value	**$/MMBtu**	7.89

Ex-Mumbai prices		
Element	**Unit**	**Value**
Naphtha price	Rs /Ton	13686
Calorific Value.naphtha	Kcal/Kg	10560
Naphtha price	Rs/Kcal	0.0013
Calorific Value. LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	11.02
Imputed value	**$/MMBtu**	7.10

Ex-Vizag prices		
Element	**Unit**	**Value**
Naphtha price	Rs /Ton	13730
Calorific Value:naphtha	Kcal/Kg	10560
Naphtha price	Rs/Kcal	0.0013
Calorific Value: LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	11.05
Imputed value	**$/MMBtu**	7.12

Industry in Gujarat is now paying a gas price of Rs 2850/thousand cubic metres which equals $1.56/MMBtu. In addition they pay royalty of 10% ($0.16/MMBtu) and transport charges depending on location. The domestic gas price is due for a revision and may soon exceed $3/MMBtu. The consumers will not surrender their allocations and change to coal. Indications are that most of them would continue to use gas. The imputed values of $1.83 - 2.39/MMBtu calculated for industrial units, therefore, underestimates the price they would be willing to pay. It is possible for cement units to reduce energy consumption from 930 kcals/kg, assumed by us in computing the imputed value, to 700 kcals/kg. There are additional benefits in terms of savings in power consumption, refractory consumption and clinker quality in changing over to gas. Cement producers should be able to pay between $2.9–3.6 / MMBtu depending on location.

How firm are the imputed values?

- There are many uncertainties in the calculation of the imputed values which are expected to be exploited by both sides during price negotiations. The principal difference in the imputed values for power and fertilizers is likely to be over efficiencies.
- For the power sector we have adopted 56% efficiency of gas turbines. Many power producers in India are more comfortable with 52% efficiency although 56% is now being guaranteed for India. This may lead to a difference of around 30 cents / MMBtu in the imputed values.
- For gas based urea production we assume that 5.4 Gcals are required for 1 MT of urea, whereas most urea producers favour 6 Gcals / MT of urea. This leads to a reduction of 40 cents / MMBtu in the imputed value of $4.2 / MMBtu computed by us for expansion units. There is a similar difference for units converting from naphtha to gas.

Annexure 14.4
Price profile of gas demand

Table 14.4.1 All India price profile of gas demand in 2006

Sector	State	Imputed Value ($/MMBtu)	Gas Demand (MMCMD)	Cumulative (MMCMD)
Glass	All India	9.80	2.65	2.65
Captive	All India	7.10	10.36	13.01
Power	Kerala	5.57	4.91	17.93
Power	Karnataka	5.46	3.24	21.16
Power	Punjab	5.10	1.41	22.58
Power	Gujarat	5.06	10.56	33.13
Urea (existing)	All India	5.05	26.35	59.48
Urea conversion	All India	4.85	13.87	73.36
Power	Haryana	4.80	3.24	76.60
Power	Delhi	4.70	4.38	80.97
Power	Rajasthan	4.67	5.06	86.03
Power	Tamil Nadu	4.41	6.98	93.01
Power	Maharashtra	4.39	10.94	103.96
Power	Uttar Pradesh	4.37	6.63	110.58
Urea (expansion)	All India	4.24	0.00	110.58
Power	Goa	4.03	0.06	110.64
Power	Andhra Pradesh	3.66	10.67	121.31
Power	Madhya Pradesh	3.64	0.67	121.98
Power	Bihar	2.97	0.00	121.98
Power	Orissa	2.97	0.00	121.98
Power	West Bengal	2.97	0.05	122.03
Cement & Paper	All India (excld. East, North east, MP, Haryana, UP)	1.64	10.56	132.59
Power	North East	1.56*	2.99	135.58
Cement & Paper	East, North east, MP, Haryana, UP	1.36	1.35	136.93

* It is assumed that gas will be saleable at Rs. 2850/MCM only in the North East although the imputed value against coal is higher.

Table 14.4.2 Price profile of gas demand for Northern India for 2006

Northern region - Punjab, Haryana, Uttar Pradesh, Rajasthan, Delhi

Sector	State	Imputed Value ($/MMBtu)	Gas Demand (MMCMD)	Cumulative (MMCMD)
Glass	Punjab	10.56	0.28	0.28
Glass	Haryana	10.56	0.19	0.47
Glass	Delhi	10.56	0.45	0.92
Glass	Uttar Pradesh	10.56	0.79	1.71
Glass	Rajasthan	10.1	0.18	1.89
Captive	Punjab	7.89	0.23	2.12
Captive	Haryana	7.89	0.44	2.57
Captive	Delhi	7.89	0.04	2.60
Captive	Uttar Pradesh	7.89	1.87	4.48
Captive	Rajasthan	7.29	0.21	4.69
Power	Punjab	5.10	1.41	6.10
Urea (existing)	Punjab	5.05	0.00	6.10
Urea (existing)	Haryana	5.05	0.00	6.10
Urea (existing)	Delhi	5.05	0.00	6.10
Urea (existing)	Uttar Pradesh	5.05	8.80	14.90
Urea (existing)	Rajasthan	5.05	1.76	16.66
Naphtha conversion	Punjab	4.85	0.81	17.47
Naphtha conversion	Haryana	4.85	0.00	17.47
Naphtha conversion	Delhi	4.85	0.00	17.47
Naphtha conversion	Rajasthan	4.85	2.40	19.88
Naphtha conversion	Uttar Pradesh	4.85	4.02	23.90
Power	Haryana	4.8	3.24	27.14
Power	Delhi	4.7	4.38	31.51
Power	Rajasthan	4.67	5.06	36.57
Power	Uttar Pradesh	4.37	6.63	43.20
Urea (expansion)	Punjab	4.24	0.00	43.20
Urea (expansion)	Haryana	4.24	0.00	43.20
Urea (expansion)	Delhi	4.24	0.00	43.20
Urea (expansion)	Rajasthan	4.24	0.00	43.20
Urea (expansion)	Uttar Pradesh	4.24	0.00	43.20
Cement & Paper	Punjab	2.24	0.65	43.85
Cement & Paper	Delhi	1.99	0.00	43.85
Cement & Paper	Rajasthan	1.79	1.55	45.40
Cement & Paper	Haryana	1.36	0.00	45.40
Cement & Paper	Uttar Pradesh	1.36	0.65	46.05

Table 14.4.3 Price profile of gas demand for Western India for 2006

Western region- Madhya Pradesh, Maharashtra, Gujarat, Goa

Sector	State	Imputed Value ($/MMBtu)	Gas Demand (MMCMD)	Cumulative (MMCMD)
Glass	Madhya Pradesh	10.56	0.03	0.03
Glass	Gujarat	10.10	0.19	0.22
Glass	Goa	10.10	0.01	0.23
Glass	Maharashtra	9.93	0.28	0.52
Captive	Madhya Pradesh	7.89	0.13	0.64
Captive	Goa	7.29	0.08	0.72
Captive	Gujarat	7.29	4.15	4.87
Captive	Maharashtra	7.10	0.60	5.47
Power	Gujarat	5.06	10.56	16.03
Urea (existing)	Goa	5.05	0.00	16.03
Urea (existing)	Madhya Pradesh	5.05	3.22	19.25
Urea (existing)	Maharashtra	5.05	4.20	23.45
Urea (existing)	Gujarat	5.05	5.51	28.96
Naphtha conversion	Goa	4.85	0.83	29.79
Naphtha conversion	Gujarat	4.85	0.00	29.79
Naphtha conversion	Madhya Pradesh	4.85	0.00	29.79
Naphtha conversion	Maharashtra	4.85	0.00	29.79
Power	Maharashtra	4.39	10.94	40.73
Urea (expansion)	Goa	4.24	0.00	40.73
Urea (expansion)	Gujarat	4.24	0.00	40.73
Urea (expansion)	Madhya Pradesh	4.24	0.00	40.73
Urea (expansion)	Maharashtra	4.24	0.00	40.73
Power	Goa	4.03	0.06	40.79
Power	Madhya Pradesh	3.64	0.67	41.46
Cement & Paper	Gujarat	2.29	2.72	44.18
Cement & Paper	Maharashtra	1.64	1.70	45.88
Cement & Paper	Goa	1.64	0.00	45.88
Cement & Paper	Madhya Pradesh	1.36	0.00	45.88

Table 14.4.4 Price profile of gas demand for Southern India for 2006

Southern region- Andhra Pradesh, Kerala, Karnataka, Tamil Nadu

Sector	State	Imputed Value ($/MMBtu)	Gas Demand (MMCMD)	Cumulative (MMCMD)
Glass	Karnataka	9.93	0.03	0.03
Glass	Andhra Pradesh	9.8	0.03	0.06
Glass	Tamil Nadu	9.8	0.03	0.09
Glass	Kerala	9.8	0.10	0.19
Captive	Andhra Pradesh	7.12	0.52	0.70
Captive	Tamil Nadu	7.12	0.11	0.82
Captive	Kerala	7.12	0.21	1.02
Captive	Karnataka	7.1	0.21	1.24
Power	Kerala	5.57	4.91	6.15
Power	Karnataka	5.46	3.24	9.39
Urea (existing)	Andhra Pradesh	5.05	2.41	11.80
Urea (existing)	Karnataka	5.05	0.00	11.80
Urea (existing)	Tamil Nadu	5.05	0.00	11.80
Urea (existing)	Kerala	5.05	0.00	11.80
Naphtha conversion	Andhra Pradesh	4.85	0.84	12.64
Naphtha conversion	Karnataka	4.85	0.83	13.47
Naphtha conversion	Tamil Nadu	4.85	2.22	15.69
Naphtha conversion	Kerala	4.85	0.81	16.50
Power	Tamil Nadu	4.41	6.98	23.48
Urea (expansion)	Andhra Pradesh	4.24	0.00	23.48
Urea (expansion)	Karnataka	4.24	0.00	23.48
Urea (expansion)	Tamil Nadu	4.24	0.00	23.48
Urea (expansion)	Kerala	4.24	0.00	23.48
Power	Andhra Pradesh	3.66	10.67	34.15
Cement & Paper	Andhra Pradesh	2.19	1.84	35.99
Cement & Paper	Tamil Nadu	2.19	0.63	36.61
Cement & Paper	Kerala	2.19	0.00	36.61
Cement & Paper	Karnataka	2.01	1.48	38.10

Table 14.4.5 Price profile of gas demand for Eastern and North-eastern India for 2006

East and North East- Bihar, Orissa, West Bengal, Assam, Arunachal Pradesh, Manipur, Meghlaya, Mizoram, Tripura, Nagaland

Sector	State	Imputed Value ($/MMBtu)	Gas Demand (2006) (MMCMD)	Cumulative (2006) (MMCMD)
Glass	Bihar	10.56	0.01	0.01
Glass	Orissa	9.80	0.00	0.01
Glass	West Bengal	9.80	0.03	0.05
Glass	North East	9.80	0.01	0.05
Captive	Bihar	7.89	0.01	0.06
Captive	Orissa	7.12	0.87	0.93
Captive	West Bengal	7.12	0.29	1.22
Captive	North East	7.12	0.40	1.62
Urea (existing)	Bihar	5.05	0.00	1.62
Urea (existing)	Orissa	5.05	0.00	1.62
Urea (existing)	West Bengal	5.05	0.00	1.62
Urea (existing)	North East	5.05	0.45	2.07
Naphtha conversion	Bihar	4.85	0.56	2.63
Naphtha conversion	Orissa	4.85	0.00	2.63
Naphtha conversion	West Bengal	4.85	0.54	3.17
Naphtha conversion	North East	4.85	0.00	3.17
Urea (expansion)	Bihar	4.24	0.00	3.17
Urea (expansion)	Orissa	4.24	0.00	3.17
Urea (expansion)	West Bengal	4.24	0.00	3.17
Urea (expansion)	North East	4.24	0.00	3.17
Power	Bihar	2.97	0.00	3.17
Power	Orissa	2.97	0.00	3.17
Power	West Bengal	2.97	0.05	3.22
Power	North East	1.56	2.99	6.21
Cement & Paper	Bihar	1.36	0.00	6.21
Cement & Paper	Orissa	1.36	0.00	6.21
Cement & Paper	West Bengal	1.36	0.00	6.21
Cement & Paper	North East	1.36	0.70	6.91

Annexure 14.5
Proposed LNG terminals in India

The supply sources identified by promoters of LNG import terminal proposals in India are listed in the Table below.

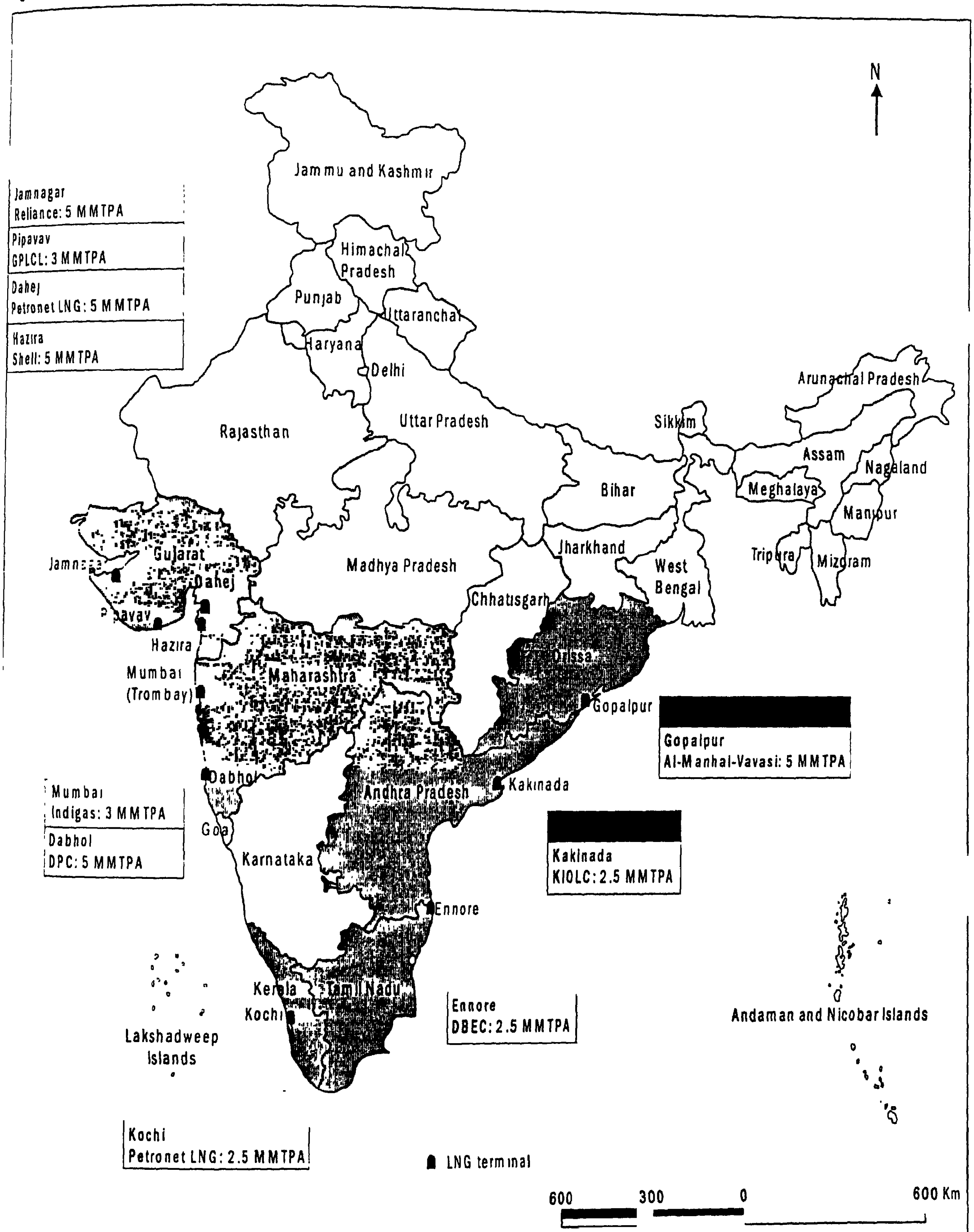
Table 14.5.1 Identified sources of supply to proposed LNG terminals in India

LNG terminal	Capacity (MMTPA)	Supply source	Remarks
Jamnagar	5.0	Iran	
Pipavav	3.0	Under identification	MoU signed earlier with Yemen voided
Dahej	5.0	Qatar	
Hazira	5.0	Shell group's sources	
Trombay	3.0	Total Elf Fina sources	
Dabhol	5.0	Oman (1.7 MMTPA) Abu Dhabi (0.54 MMTPA)	Balance quantity yet to be sourced
Kochi	2.5	Qatar	
Ennore	2.5	Qatar	
Kakinada	2.5	To be decided	Malaysia, a contender
Gopalpur	5.0	Australia	
Total	**38.5**		

The locations of the ten proposals listed in Table 14.5.1 are shown in map 14.5.1. The status of these proposals is examined below.

Map. 14.5.1 Proposed LNG terminals

Figure 7.1. Proposed LNG terminals



Jamnagar LNG terminal

The Reliance group of India has entered into a MoU with the National Iranian Oil Company (NIOC) and British Petroleum (BP) to set up a 8 MMTPA liquefaction facility for natural gas in Iran. Gas from Iran's offshore South Pars Field-Phase II is to be transported through a pipeline to Assaluyeh on the Persian Gulf where the liquefaction plant is to be put up along with LNG export facilities. This is the first MoU signed by NIOC for development of a LNG export terminal in Iran.

A joint venture company is under formation to take in hand work on the above liquefaction and export facility. The equity shareholding is likely to be NIOC-40%, Reliance-25% and BP-25%, with the remaining 10% to be allotted to a fourth partner who is yet to be selected. Terms of the JV agreement and size of the equity base of the new company are being discussed between the partners. Meanwhile, GAIL has staked its claim for equity participation in the JV to be formed. Reliance is expected to get marketing rights for 5 to 6 MMTPA of LNG. BP will, in that case, draw the remaining 2 to 3 MMTPA of LNG for marketing themselves. It is understood that feasibility studies for the liquefaction plant have been completed and the target is to have it commissioned by 2007.

For despatch of petroleum products by ocean going tankers, the 27 MMTPA Reliance refinery at Jamnagar has a jetty extending nearly 7 km into the sea with 4 berths. The draught available is suitable for receiving LNG tankers of 135,000 cu metres capacity. Reliance also has spare land available and is thus in a position to use its existing infrastructure to construct the LNG import terminal relatively quickly. The capacity of the terminal is tentatively planned at 5 MMTPA, with provision to enlarge the capacity to 10 MMPTA.

Pipavav LNG terminal

Located on the west coast of India in the state of Gujarat, Pipavav is the country's first port developed with private sector initiative, capital and management. The Gujarat Pipavav Port Limited (GPPL) which undertook the development work and is now administering and managing the port operations. The port has a natural draught of 9.5 to 11 metres, which is dredged to a depth of 12.5 metres to receive ships upto 45,000 DWT. There is a 300 metres long jetty with a separate terminal to receive LPG and liquid chemical vessels. A joint venture company promoted by GPPL and the Railways will link Pipavav by a 14 km new rail line to Rajula, and convert the 250 km Rajula – Surendranagar section from metre to broad gauge at a cost of Rs 294 crores.

The plan for the port has a provision for a separate LNG jetty and terminal next to the LPG import facilities. The Gujarat Pipavav LNG Limited (GPLNG) owned by British Gas (BG) plans to set up an LNG import terminal of 2.5 MMTPA capacity expandable to 10 MMTPA. BG plans a subsea pipeline from Pipavav to Hazira to gain access to important gas consumers in and around in Hazira, and the strategic HBJ pipeline. It would also enable BG to avail of the recently commissioned Hazira – Ankleshwar pipeline of their affiliate Gujarat Gas Company Ltd (GGCL) to further develop and enlarge gas marketing through GGCL's old infrastructure in South Gujarat.

GPLNG has signed an MoU with NTPC granting it a 26% stake in the company. NTPC agreed to source its entire gas demand of 1.6 MMTPA exclusively from GPLNG for the proposed 650 MW second stage expansion of its Kawas and Gandhar power plants. However, NTPC has recently indicated that it has not tied up LNG supplies from any source. GPLNG has invited expression of interest for the supply of 5.3 MMTPA of LNG. Eight probable suppliers have reportedly been short-listed, including Yemen LNG. The progress made by the neighbouring LNG terminal proposals at Dahej and Hazira has relegated the Pipavav proposal to the background. Pipavav's distance from the main gas consuming centres of Gujarat has added to its handicap.

Dahej LNG terminal

The Ministry of Petroleum & Natural Gas, Government of India approved the formation of a joint venture company in May, 1997 between GAIL, ONGC, IOC and BPCL to develop facilities for the import of LNG. The company was incorporated in April, 1998 under the name of Petronet LNG Ltd (PLL) with an authorised capital of Rs 1200 crores. Gas de France has joined the company as a strategic partner.

Dahej has been selected as the terminal site because of the substantial gas demand in its vicinity from existing and prospective consumers and possible access to the gas transmission infrastructure. The draught at the jetty head will be 14.5 metres. A breakwater will be constructed to withstand the severe maritime conditions during the monsoon period. The terminal capacity is to be 5 MMTPA expandable to 10 MMTPA. LNG storage will consist of 2 × 160,000 cubic metre tanks, with provision to add a third tank. The EPC contract for the terminal was awarded in December 2000. Foster Wheeler Energy Ltd. of the U.K. has been appointed as the project management consultants.

A long-term purchase agreement was signed by PLL in July 1999 with Rasgas of Qatar for the supply of 5 MMTPA of LNG (which can increase to 7.5 MMTPA by giving necessary notice) on fob basis. The 25 years contract effective July 2003 envisages a requirement of 5 MMTPA at Dahej and 2.5 MMTPA at Kochi but gives PLL the option to take the entire quantity of 7.5 MMTPA at Dahej. The LNG price payable by PLL will be variable and linked to the average price of a basket of crude oils.

Rasgas is reported to have agreed to give PLL a 5% stake in the 5 MMPTA LNG liquefaction - phase II plant in Qatar.

It has been decided that gas will be marketed by the following companies in the indicated proportions GAIL 60%, IOC 30%, and BPCL 10%.

The companies will use the existing pipeline transmission infrastructure of GAIL who will be exclusively responsible for gas transportation for all marketers against payment of a transportation charge. Any additional pipelines to be laid will be the responsibility of GAIL.

Hazira LNG terminal

In 1997, the Gujarat Maritime Board (GMB) on behalf of the state government of Gujarat invited applications for the development of an all weather multi-cargo port at Hazira. The initiative was to be "LNG driven", as the large requirement for natural gas in north-west India would make the Hazira port project an attractive and viable proposition. In 1999 Shell and its Indian partner Essar were awarded the rights to develop the project.

The project is a fully owned development by the Royal Dutch/Shell group. This project is being constructed on balance sheet financing and therefore no financial closure is required. Shell has floated two fully owned companies for the development of Hazira port and the LNG terminal. The Hazira Port Private Ltd. (HPPL) will provide all the facilities for a multi-cargo port at Hazira including development of a suitable approach channel, and reclamation of land from the sea. The Hazira LNG Private Ltd (HLPL) will handle installation of LNG storage tanks, receipt, regasification, transfer pipelines and send out facilities. Shell has recently obtained government approval to increase their investment from $130 million to $200 million.

The port will consist of a 1000 × 1200 metres basin, with a draught of 14 metres. Vessels will approach the basin through a channel dredged to a draught of 12.5 metres but capable of being eventually dredged to 17.5 metres. A breakwater 1.2 km to 1.4 km long is to be put up at a water depth of 10 to12 metres. In its first phase, the port will accommodate LNG vessel upto 145,000

cubic metres, dry bulk vessels upto 150,000 dwt, and general dry cargo vessel upto 30,000 dwt.

The capacity of the terminal will be 5 MMTPA capable of being doubled. Two double walled cryogenic tanks of 180,000 cubic metres capacity each are to be installed initially. FIPB and CCEA clearances have been received. The Environmental Impact Assessment has been completed. Approvals have been received from the Gujarat Pollution Control Board and the CRZ administering authorities. The Ministry of Environment & Forests has accorded environmental clearance. Award of work to the selected EPC contractor is being finalized. The terminal is targeted to be commissioned in the first quarter of 2004. Shell is uniquely placed to source and ship LNG not only from the Middle East but also from south-east Asia and Australia. The precise sources of supply have not yet been disclosed.

Trombay LNG terminal

Indigas, a company owned equally by Tata Power Company, Total Gas and Power India - a wholly owned subsidiary of Total Fina Elf - and GAIL was planning a terminal at Trombay with a capacity of 3.3 MMTPA. About 1 MMTPA was to be consumed by TPC and the balance sold to local customers. As of now, it seems unlikely that the project will take off.

Dabhol LNG terminal

The terminal capacity under construction is 5 MMTPA. A full-fledged port is ready at Dabhol with a 1.8 km long jetty to receive LNG ships of 135,000 cubic metres capacity. A 2300 metres long breakwater has been provided. Three storage tanks of 160,000 cubic metres capacity each are being installed, with provision for building a fourth tank.

An Enron subsidiary called Metgas entered into an agreement with Oman-LNG in 1998 for the import of 1.26 MMTPA of LNG at Dabhol starting 2001. Later that year, Metgas signed a second agreement with Ad Gas of Abu Dhabi for a further 0.54 MMTPA of LNG. DPC's gas requirements for power generation at Dabhol was to be met from these two sources.

Metgas is also reported to have signed a confirmation of intent with Malaysia LNG Tiga for the supply of 2.6 MMTPA of LNG, starting mid-2002 for the supply of gas to consumers in Maharashtra.

The LNG terminal was to be completed by end 2001 but its commissioning is now uncertain. Several companies like GAIL and Reliance are said to be in the

race to acquire the LNG terminal but it may be some time before the negotiations are completed.

Kochi LNG terminal

The New Vypeen island situated about 4 km north-west of the Kochi Port Trust office has been selected as the site for the terminal. A 170 metres long jetty is to be built close to the terminal site. Existing draught available at the jetty head is 12 metres and will require dredging to 14.5 metres. The maritime conditions during monsoon months are not as severe as at Dahej and the tidal waves not very high. Nevertheless, 2 to 3 metres high breakwaters are to be built to the north and south of the island.

The terminal capacity is to be 2.5 MMTPA expandable to 5 MMTPA. LNG storage will consist of 2 × 110,000 cu metre tanks, with the provision to add a third tank. A detailed feasibility report of Kochi terminal had been prepared by Flour Daniel/Mitsubishi. The estimated cost of the project is around Rs 1600 crores.

PLL are working towards commissioning the terminal by the year 2005, though much remains to be done to attain this objective. In particular, it would be difficult to locate the customers for gas.

Ennore LNG terminal

The Ennore port has been notified by the Government of India as a major port under the Indian Ports Act 1908 and has been registered as a company, viz. Ennore Port Limited. Construction of the first phase of Ennore port has been funded by assistance from the Asian Development Bank and partly through investment by Chennai Port Trust and the Government of India. TIDCO has invited bids for a 2.5 MMTPA LNG terminal and 1850 MW capacity power plant to be located within the Ennore port area. The Dakshin Bharat Energy Consortium won this project. The consortium consists of 5 companies namely: Grasim Industries Limited, CMS Energy Asia, Siemens Project Venture GmBH, Germany, Unocal Bharat Ltd and Woodside Energy, Australia. The consortium has registered a new company, TN LNG and Power Co. Pvt. Ltd (TNLPC) to develop this project.

The LNG storage will consist of two 120,000 cu. metre tanks, with double walls and full containment. The terminal will be put up by TNLPC on BOO basis. The 1850 MW power plant consists of 5 units of advanced class gas turbines from Siemens, Germany operating on combined cycle mode. Construction of the power plant by TNLPC at their cost will be on BOOT basis to operate the plant

for 20 years. A firm year wise tariff has been committed for 20 years for supply of power, as per their quotation under the ICB procedure.

The Power Trading Corporation (PTC) will purchase the entire power produced under a 20-year firm Power Purchase Agreement (PPA). The Power Grid Corporation of India Ltd. (PGCIL) will, in turn, execute transmission services agreements and back-to-back PPAs with the State Electricity Boards. PTC is likely to resell power to SEBs in the southern region follows: Tamil Nadu - 750 MW, Karnataka - 300 MW, and Kerala - 200 MW with the balance quantity of 600 MW to be decided. The ability to absorb all the power to be generated will be a key factor in the materialization of this project.

The project has received FIPB approval and CCEA approval is expected shortly. TNLPC has been permitted to bring in $426 million as foreign equity through its five share holders and a further $656 million as foreign debt thus amounting to total foreign direct investment inflow of $1082 million. Detailed feasibility and basic design engineering studies have been undertaken and separate EPC contractors have been identified for the power plant and LNG terminal.

During the Indian Prime Minister's visit to USA in September 2000, a Joint Development Agreement was signed by the project developers consortium, through its shareholders, with PTC signifying Government of India's commitment to the project, support by way of payment security mechanism (PSM), and interest in achieving time bound completion. The payment security mechanism, however, is not yet in place and is reportedly causing concern to the promoters. It is envisaged that financial closure would be achieved by March, 2002 so that project construction can start thereafter.

LNG is being sourced from Rasgas, Qatar. Heads of agreement have been signed and Rasgas for the LNG supply.

While 1.8 MMTPA gas will be supplied to the 1850 MW power plant, 0.7 MMTPA gas is to be sold to the Madras Chemicals and Fertilizers Ltd. and other industries and consumers through short distance pipelines by setting up a separate marketing company.

Kakinada LNG terminal

A consortium led by IOC plans to set up an LNG import terminal and a 1000 MW power plant at Kakinada port on the east coast. The Andhra Pradesh state government has issued a letter of support to the consortium. The "Kakinada Indian oil LNG consortium" comprises IOC, BP, Petronas and Cocanada Port Company Ltd. (the company operating Kakinada port at present) as partners.

The equity participation has yet to be decided though IOC is likely to take a major share. Andhra Pradesh state government may also take some equity through the Andhra Pradesh Power Generation Corporation. A detailed Project Report (DPR) of the LNG terminal prepared by Tractebel of Belgium has been submitted by KIOCL to the Andhra Pradesh government in March 2001 and comments are awaited. The capacity of the terminal will be 2.5 MMTPA initially, expandable to 10 MMTPA. The existing channel in Kakinada port is dredged to a draught of 10 metres for smaller vessels received at present. The channel can be further dredged to receive LNG ships of 135,000 cubic metre capacity. The port has enough area to construct a LNG jetty with the required turning circle. No breakwater is required. Enough open government land exists adjacent to the port boundary where a suitable plot of the required size can be provided on lease by the state government. According to the central government notification of August 2000, construction of LNG terminal facilities in the CRZ is permitted. Discussions have been held by IOC with Petronas for LNG supplies but no firm supply agreement has been reached so far. Negotiations with other LNG suppliers in the Far East are contemplated.

Gopalpur LNG terminal and integrated complex

The Al Manhal International Group (AMIG) of the United Arab Emirates, the Vavasi Oil & Gas (P) Ltd., a company of Indian technocrats, and the Industrial Promotion & Investment Corporation of Orissa Ltd have jointly proposed to set up an ambitious integrated complex at Gopalpur port on the east coast. The US $ 6 billion plan includes an LNG import terminal, a large gas based power plant, a gas based urea-ammonia plant, a naphtha-cum-gas cracker along with a petrochemical plant and two long distance pipelines carrying natural gas to consumers in the northern and southern parts of the country. The promoters are reported to be also considering acquisition and operation of the ships required for transporting LNG to the proposed terminal at Gopalpur.

The Adani Group, which has successfully developed the Mundra port near Kandla on the west coast, has signed a MoU with Orissa state government to develop a deep water port at Gopalpur under the build-own-operate-transfer (BOOT) scheme for a concessional period of 30 years. The Adani group will be constructing solid and liquid cargo jetties after dredging and constructing breakwaters. The Gopalpur LNG Ltd (GLL) will construct and own the LNG terminal. The equity structure of the company is reported to be on the following lines AMIG & Vasavi (50%), Ipicol (5%), Australia LNG (25%), strategic partners (15%), and others (15%). The project cost is estimated at S450 million.

The Al Manhal-Vavasi consortium has chosen Australia LNG (ALNG) as their LNG supplier. The consortium has signed a 'Heads of Agreement' followed by a 'Confirmation of Intent' with ALNG to secure 5 MMTPA of LNG for 20 years commencing from the year 2004. The Confirmation of Intent also provides an opportunity to ALNG to exercise an option for taking equity in GLL.
The project is highly ambitious and it is doubtful if it will come through.

Annexures
Part-3
Value Added Products

Annexure 15.1
Indian LPG Market

Introduction

LPG is primarily marketed by the public sector oil companies – Indian Oil Corporation (IOC), Bharat Petroleum Corporation Ltd (BPCL) and Hindustan Petroleum Corporation Ltd (HPCL). The IBP Co Ltd has commenced its LPG operations recently only. In addition, LPG imports be private parties are also allowed. LPG marketing was liberalised with the introduction of the Parallel Marketing System (PMS) in 1993, which allowed parallel marketers to import, store, bottle and market LPG. The success of parallel marketers has, however, been somewhat restricted on account of the availability of LPG at subsidised prices (domestic segment only) from the PSU (public sector units) companies.

Sales

In contrast to a decadal growth rate of 5% for consumption of all petroleum products in the country, LPG sales have recorded an average growth rate of 10.6% over the last decade. Due to constraints in availability of LPG in the past, these figures pertain more to supply volumes rather than demand.

However, of late with the commissioning new refineries and expansions of existing ones, supply constraints have been relaxed considerably. Growth in LPG sales in 2000/01 slipped below 10% for the first time since 1994/95 (Table 15.1.1). These trends reflect a saturation in the domestic LPG segment, which primarily targets the urban areas. The waiting list of 11 million customers in end of 1999 has now been liquidated with release of 12.7 million new connections in 2000/01. The government is now planning to extend the reach of LPG into rural areas. The Ministry of Petroleum & Natural Gas intends to set up 1200 new LPG distributors in the current fiscal, primarily to cater to rural needs. The public sector oil companies are also devising new strategies to meet rural requirements such as mobile LPG filling stations and smaller cylinder sizes.

Table 15.1.1 Trends in LPG consumption: TMT

Year	LPG Consumption	Growth Rate
1990/91	2415	6.5%
1991/92	2650	9.7%
1992/93	2866	8.2%
1993/94	3113	8.6%

Year	LPG Consumption	Growth Rate
1994/95	3434	10.3%
1995/96	3849	12.1%
1996/97	4267	10.9%
1997/98	4803	12.6%
1998/99	5352	11.4%
1999/00	6029	12.6%
2000/01	6610	9.6%

LPG sales can be classified into two main categories – bulk sales and bottled sales. Bulk industrial/commercial sales reflect about 10% of the total LPG consumption in the country. Bottled LPG (14.2 kg cylinder) is primarily meant for the domestic market though there are some industrial/commercial sales in 19 kg and 50 kg cylinders.

Supply

LPG availability from refineries, fractionators and imports aggregated 7001 TMT in 2000/01. After the commissioning of Reliance's 27 MMTPA refinery at Jamnagar, the need for LPG imports has reduced substantially. As against typical LPG yields of 2-4%, the LPG yield at the Jamnagar refinery is as high as 7.4% (Table 15.1.2). LPG imports consequently came down from 1587 TMT in 1999/00 to 853 TMT in 2000/01.

Of the 853 TMT of LPG imports in 2000/01, 178 TMT were imports by parallel marketers while the rest were imports by PSUs. Key players involved in parallel marketing of LPG include – SHV Energy, Shri Shakti, Caltex, Shell, Elf Gas and Mobil.

LPG production from fractionators aggregated 2050 TMT in 2000/01, with ONGC accounting for about 60% of the total production. Details of LPG production from fractionators are summarised in Table 15.1.3.

Table 15.1.2 LPG availability from refineries (TMT)

Company	Location	Capacity	Throughput	LPG Production	LPG Yield
BPCL	Mumbai	6900	8664	363	4.2%
HPCL	Mumbai	5500	5575	134	2.4%
RPL	Jamnagar	27000	25715	1901	7.4%
IOC	Koyali	12500	12004	313	2.6%
Western Region Total		51900	51959	2712	
IOC	Panipat	6000	5707	157	2.8%
IOC	Mathura	7500	7132	193	2.7%
Northern Region Total		13500	12839	350	
IOC	Barauni	4200	3123	60	1.9%
IOC	Haldia	3750	3874	53	1.4%

Eastern Region Total		7950	6996	113	
IOC	Guwahati	1000	708	14	2.0%
IOC	Digboi	650	678	2	0.4%
BRPL	Bongaigaon	2350	1490	25	1.7%
NRL	Numaligarh	3000	1451	26	1.8%
North Eastern Region Total		7000	4327	68	
CPCL	Madras	6500	6046	127	2.1%
KRL	Kochi	7500	7520	345	4.6%
CPCL	Nanmanam	500	579	18	3.1%
HPCL	Vizag	7500	6405	229	3.6%
HPCL/Birla	Mangalore	9690	6439	137	2.1%
Southern Region Total		31690	26989	856	
Total		112040	103111	4098	

Table 15.1.3 LPG production from fractionators: 2000/01 (TMT)

Fractionator	Production
ONGC:	
Uran	530
Hazira	619
Ankaleshwar	12
Gandhar	54
ONGC Total	1214
GAIL	836
Total	2050

Regional demand/supply balance

On account of a concentration of refining capacity and fractionators in the western part of the country, there are acute imbalances with regards to regional demand/supply positions. The western region has a heavy surplus while the other regions of the country have deficits (Table 15.1.4).

Table 15.1.4 Regional LPG demand supply balance: 2000/01 (TMT)

Region	Demand*	Availability#	Deficit
North	2214	528	1686
West	1758	4495	-2737
East	814	270	544
South	1824	856	968
Total	6610	6148	462

* PSU sales only
# Refineries & fractionators only

The western surplus, however, fails to meet the deficits in other regions and overall imports are necessitated.

Demand/supply outlook

Demand

Demand projections used in this analysis are those as per the Tenth Plan Working Group. These draw upon the work undertaken by Marketing & Development Research Associates on long-term LPG demand outlook for the country. Estimates have been worked out for domestic, industrial/commercial and automotive sectors.

Domestic demand has been separately worked out for the urban and rural sectors. While estimates for the urban sector primarily rely on data of marketing companies, rural penetration was estimated from likely trends in household incomes and a survey of intentions of non-users to switch to LPG. Households with monthly income below Rs 2,500 were not considered as potential users.

Estimates for LPG penetration in the automotive sector was again survey based. Factors taken into consideration included vehicle usage and fuel consumption as assessed from a field study. Demand estimates were derived in relation to price of Auto LPG vis-à-vis that of motor spirit.

Sectoral demand projections for the Tenth Plan period are summarised in Table 15.1.6.

Table 15.1.6 LPG demand projections (TMT)

Year	Domestic			Commercial	Industrial	Automotive	Total
	Urban	Rural	Total				
2000/01	5064	1442	6506	402	236	0	7144
2001/02	5360	1742	7102	437	255	261	8055
2002/03	5662	2052	7714	474	274	294	8756
2003/04	6023	2368	8391	513	294	329	9527
2004/05	6384	2693	9077	552	315	366	10310
2005/06	6765	3025	9790	593	336	405	11124
2006/07	7164	3364	10528	635	358	445	11966

Supply

The analysis on supply outlook takes into consideration expansions of existing refineries, commissioning of new ones and LPG production from fractionators. The Tenth plans target of refining capacity addition of 106 MMTPA seems ambitious, and this has been scaled down to 56 MMTPA for the purpose of this analysis.

Gas availability from fractionators on the other hand is expected to decline in the future. LPG supply estimates for the period under consideration are presented below in Table 15.1.7.

Table 15.1.7 LPG supply outlook (TMT)

Year	Refineries	Fractionators	Total
2001/02	4479	1950	6428
2002/03	4479	1849	6328
2003/04	4928	1838	6766
2004/05	5131	1772	6903
2005/06	6031	1735	7766
2006/07	7639	1709	9348

Demand/supply balance

A review of the demand-supply position for LPG indicates that LPG supply would remain in deficit (Table 15.1.8).

Table 15.1.8 LPG demand-supply outlook (TMT)

Year	Demand	Supply	Deficit
2001/02	8055	6428	1627
2002/03	8776	6328	2448
2003/04	9528	6766	2762
2004/05	10310	6903	3407
2005/06	11123	7766	3357
2006/07	11966	9348	2618

The deficit peaks by 2004/05 and thereafter reduces progressively as additional refining capacity becomes operational. Imports, however, would be necessary to bridge the gap between demand and supply.

Annexure 15.2
LPG demand-supply balance in the western region

Given ONGC's production facilities in the west, a more detailed examination of the western surplus is warranted. A summary of current state-wise LPG availability and bottling plant capacities in the western region is presented in Table 15.2.1.

Table 15.2.1 LPG demand-supply balance in the western region (TMT)

State	Supply Source	Availability	Bottling Plants	Demand	Surplus
Gujarat	RPL	1901	Rajkot	44	
	Hazira	619	Bhavnagar	44	
	Ankaleshwar	12	Hazira	44	
	Gandhar	54	Ankaleshwar	44	
	Gandhar (GAIL)	209	Gandhar	68	
	Koyali	313	Ahmedabad	66	
	Vaghodia	73	Gandhinagar	26	
			Hanyala	34	
Sub-Total		3181		370	2811
Maharashtra	HPC Refinery	134	Uran	132	
	BPC Refinery	363	Mumbai	122	
	Uran	530	Usar	109	
	Usar	139	Jalgaon	44	
			Aurangabad	44	
			Chandrapur	44	
			Khapri	44	
			Chakan	44	
			Pune	22	
			Manmad	34	
			Akola	44	
			Miraj	44	
			Solapur	44	
			Satara	22	
Sub-Total		1166		793	373
Madhya Pradesh	Vijaipur	406	Bhopal	88	
			Bhitoni	44	
			Manglia	34	
			Raipur	44	
			Pitampur	22	
Sub-Total		406		232	174

The maximum surplus appears in the state of Gujarat on account of the concentration of refining capacity and fractionators in the state. The real demand-supply position, however, is likely to be a bit different depending upon actual flows from supply sources to demand centres. For instance, the bulk of RPL's production is likely to be evacuated to the northern markets via the 1.7

MMTPA Jamnagar-Loni LPG pipeline. Despite this movement, a surplus of about 1 MMT remains.

On the other hand, the surplus in Madhya Pradesh may turn out to be higher as the Raipur market is better supplied from the Vishakapatnam refinery.

Outlook for the western region

The western region accounts for about 70% of the current LPG production, while the demand in the west adds up to only 27%. A large surplus in the west, thus, follows. The demand-supply position worsens as additional refining capacity is brought on stream (Tables 15.2.2 & 15.2.3).

Table 15.2.2 Outlook on LPG availability in the west (TMT)

Supply source	Year	Availability
Existing:		
Refineries		2712
Fractionators		1783
Additional supplies:		
HPC Mumbai	2002/03	8
RPL	2003/04	444
BPC Mumbai	2004/05	214
RPL	2006/07	1257
Fractionators*	2006/07	-341
Net LPG availability	**2006/07**	**6076**

* LPG production from fractionators expected to decline in the projection period

Table 15.2.3 Projected demand-supply balance in the western region (TMT)

Year	Demand	Supply	Surplus
2001/02	2142	4394	2252
2002/03	2334	4302	1968
2003/04	2534	4734	2200
2004/05	2742	4882	2140
2005/06	2958	4845	1887
2006/07	3182	6076	2894

The surplus in the west increases from about 2.3 MMT to 2.9 MMT by the year 2006/07. The bulk of this surplus would have to be moved northwards to meet the deficits in the northern markets.

Annexure 15.3

Estimated filling charges for a new bottling plant

Particulars	Unit	Year (Base Year 2000) 2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Capital Cost	Million	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
IDC	Million	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Capital Cost including IDC	Million	390	390	390	390	390	390	390	390	390	390	390	390	390	390	390
Costs																
Fixed Cost																
Interest	Million	38	34	31	27	23	19	15	11	8	4					
Depreciation	Million	19	19	19	19	19	19	19	19	19	19	19	19	19	19	117
ROE	Million	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
O&M	Million	11	12	13	14	15	16	17	18	20	21	22	24	26	27	29
Total Fixed Cost	Million	83	80	77	74	71	69	66	63	61	58	56	57	59	61	160
PV Factor		1.00	1.00	0.88	0.78	0.69	0.60	0.53	0.47	0.41	0.37	0.32	0.28	0.25	0.22	0.19
PV of Annualised Cost		83	80	68	58	49	41	35	30	25	21	18	16	15	13	31
Annualised Cost	Million	92														
Annualised Cost	Rs/MT	2091														
REPAYMENT SCHEDULE																
Loan outstanding at beginning of year	Million	273	246	218	191	164	136	109	82	55	27					
Interest	Million	38	34	31	27	23	19	15	11	8	4					
Repayment	Million	27	27	27	27	27	27	27	27	27	27					
Loan outstanding at end of year	Million	246	218	191	164	136	109	82	55	27	0					
Parameters																
Capital Cost	Rs Crores	30														

Financial Parameters

Debt Component	70%
Equity Component	30%
Interest rate for Loan	14%
Return on equity	12%
Depreciation	5.0%
Discount rate	13.4%
Operating cost	3.0%
Escalation	7.0%

Operating Costs

BPC NR Capacity	MT	445000
Operating costs	Rs Million	115.2
Est. operating costs for 44 TMT BP	Rs Million	11.39
Operating costs per unit	Rs/MT	259

Annexure 16.1
Naphtha market overview

The following table shows the region wise sales of OMCs for the year 2000-01.

Table 16.1.1 Sector wise and region wise naphtha sales by PSUs (TMT)

	Power/Steel	Fertilizer	Petrochemical	Processors	Total
Northern	145.6	1740.9	-	66.0	1952.7
Western	1545 1	885.8	1185.8	80.5	3697.0
Southern	714.8	1199.6	1648.5	2.2	1943.9
Eastern	0.4	46.5	435.4	-	482.4
Total	2405.9	3872.8	1648.5	148.7	8076.00

Source. Industrial performance review. April 2001

The all-India sale in the year 1999-2000 was 8011.2 TMT, which meant an increase of 0.80% in the year 2000-01 over the last year. Consumer wise naphtha sales for the western region is given in Annexure 15.6.

As this table shows, the western region accounts for 45.77% of total naphtha consumption followed by northern region with 24.17% and Southern region with 24.07%. Sector wise, fertiliser accounted for 47.9% followed by Power/Steel with 29.79%. These figures, however, conceal the fact that petrochemical sector imports large quantity of naphtha since not all naphtha produced in India is petrochemical grade naphtha. If imports are also included in consumption, then petrochemical sector accounts for 42% and power/steel and fertiliser account for 33% and 25% respectively.

The imports and exports of naphtha have been as follows-

Table 16.1.2 Naphtha imports and exports (TMT)

	1996/97	1997/98	1998/99	1999/00	2000/01
Imports	15	1874	2407	1917	3165
Public Sector			168	230	340
Private Sector	15	1874	2239	1687	2825
Exports	2589	2048	720	583	2882
Net Imports	-2574	-174	1687	1334	283

Source. OCC

Naphtha imports by the private sector are undertaken mainly by Reliance Petrochemicals, Haldia Petrochemicals and Dabhol Power Company (this has now stopped). Reliance engages in swap deals where it sells its own naphtha in return for petrochemical grade naphtha. This provides a tax benefit for it since it

does not have to pay a sales tax of 24% on purchase from its own refinery. Moreover, there is a 10% duty rebate on exports.

Existing players

Presently, there are four public sector undertakings that market naphtha in the country, besides ONGC. These are the four Oil Marketing Companies (OMCs): Indian Oil Corporation (IOC) (including IBP), Bharat Petroleum Corporation Limited (BPCL) and Hindustan Petroleum Corporation Limited (HPCL). Mangalore Refineries Limited (MRL) being a joint venture refinery, sells some quantity of naphtha directly to MFL Chennai.
Company wise naphtha sales is shown below.

Table 16.1..3 Region wise, company wise and sector wise naphtha sales (TMT)

	Fertilizer				Power/Steel				Petrochemicals				Processor	
	N	W	E	S	N	W	E	S	N	W	E	S	N	W
IOC	1587.3	462.1	46.5	812.5	60	1012.1	6.4	127		639.6	418.6	14	66	68.6
BPC	153.6	17.6			82.2	133.5		342.7		546.2	16.8			10.8
HPC		406.1		154.3	3.4	399.5						13.3		1.1
MRL				232.8										

Source: Industrial performance review, April 2001
Note: For this table, IOC(M) and IOC(AOD) and IBP have been combined into IOC.
N: Northern Region; W: Western Region; E: Eastern Region; S: Southern Region

IOC is the dominant seller in the western region market with a market share of 59% with rest of the market equally distributed between HPCL and BPCL. However, BPCL has a bigger share than HPCL in the petrochemicals sector whereas HPCL has a bigger share than BPCL in the fertiliser and power/steel sector.

IOC, BPCL and HPCL are integrated marketing and refining companies with huge refining capacities. These companies produce over 8 million tonnes of naphtha annually and sell it either in India or export it. They produce and market many other controlled and decontrolled products. These companies also have certain hospitality arrangements among themselves, which allows them to use each other's facilities.

On the other hand, ONGC is primarily an exploration and production organisation with a handful of value added products, extracted from offshore gas and condensate. Its production is concentrated in the western region of the country though it has recently started a small primary refinery in Tatipaka, Tamil Nadu.

Sourcing of naphtha

The following table shows the production and sale of naphtha in the year 2000-01 by the three OMCs in the western region.

Table 16.1.4 Company wise production versus sales for the western region (TMT)

	HPC	BPC	KOY (IOC)	TOTAL WR
Production	603.1	1148.3	1233.8	2985.2
Sales	806.7	708.1	2182.3	3697.1
Sales - production gap	-203.6	440.2	-948.5	-711.9

As this table shows, except BPC, all the other two public sector companies sell more naphtha than their own production. HPC & IOC source naphtha either from ONGC or from refineries outside the region.

In the period May 2000 to February 2001, ONGC exported 300 TMT of naphtha, mainly to Japan out of the total production of 1664 TMT. Thus, OMCs sold around 1364 TMT of naphtha in the domestic market. And given the fact that western region was in deficit, this naphtha was sold primarily in the western region. But since the production of naphtha by ONGC was larger than the deficit in the western region, some its naphtha was sold to consumers outside the region like Chambal Fertilisers and Mangalore Chemicals and Fertilisers Limited.

Annexure 16.2
Naphtha demand supply scenario

Demand projections

The naphtha demand projections have been estimated taking into account the fact that petrochemical industry imports large quantity of naphtha due to quality differences. In the following analyses, the demand for naphtha originating from imports has been excluded for the same reason. Since ONGC's production is concentrated in the Western region, the demand estimates will be given separately for Western region also.

Projections for the petrochemical sector

The petrochemical sector has been growing at an impressive rate of 14% per annum in the last decade. Based on these growth rates and the number of proposals for setting up the petrochemical plants, the Chemical Manufacturer's Association estimates that that petrochemical industry will continue to grow at 5% per annum for the next decade. This then gives us the naphtha demand originating from the petrochemical sector, excluding imports.

Table 16.2.1 Projected naphtha demand from the petrochemical sector (TMT)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Demand	1887	1981	2080	2184	2293	2408

In the western region, a number of new projects have been cleared by the government like Reliance's Jamnagar expansion and IPCL expansion.

Table 16.2.2 Projected naphtha demand by the petrochemical sector for Western region (TMT)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Western Region	1330	1396	1466	1539	1616	1697

Projections for the power sector

According to the liquid fuel policy announced by government of India in 1997, about 12000 MW capacity was to be installed on naphtha. However, so far only 2000 MW has been set up. This is due to the high prices of naphtha that has raised the cost of generation. Due to high costs, many naphtha based power generators will shift to gas as and when gas becomes available. These are shown below.

Table 16.2.3 LNG for power plants

Power plant	Current naphtha off take	Source of LNG	Expected year of shift
Essar power	39 TMT	Petronet Dahej	2005
NTPC Kayamkulam	342 TMT	Petronet Cochin	Uncertain
APGPCL	89 TMT	Local gas	2004
BSES	36 TMT	Local gas	2004
Dabhol	577 TMT	Dabhol	2003
LANCO	157 TMT	Local gas	2001

Source. TERI estimates

Because of this shift, demand for naphtha from the power sector will be declining over the years as shown below.

Table 16.2.4 Projected demand of naphtha by power sector (TMT)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Power/Steel	2250	2250	1673	1548	1509	1509

In the western region, power plants like Essar and Dabhol will not consume any naphtha as and when gas is available to these.

Table 16.2.5 Projected demand for naphtha by power sector for Western region (TMT)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Western Region	**1545**	**1545**	**968**	**968**	**929**	**929**
Current Sales	1545	1545	1545	1545	1545	1545
Deductions	*0*	*0*	*577*	*577*	*616*	*616*
Dabhol			577	577	577	577
Essar					39	39

Projections for the fertiliser sector

For fertiliser sector also, it has been assumed that the urea plants will shift to LNG as and when it becomes available. Moreover, four existing plants – Kota, Gadepan, Kanpur and Phulpur will shift to LNG in the year 2005/6 with the coming up of Petronet's Dahej LNG terminal. The resulting naphtha demand will be as follows-

Table 16.2.6 Projected demand for naphtha by fertiliser sector (TMT)

	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Fertiliser	3873	3873	3873	3873	3873	2750	1730

The fertiliser plants in the western region expected to shift to gas are KRIBHCO Hazira plant, NFL Vijaypur, IFFCO Kalol and GSFC Baroda.

Table 16.2.7 Projected demand for naphtha by fertiliser sector in Western sector (TMT)

	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Western Region	**886**	**886**	**886**	**886**	**886**	**483**	**483**
Current Sales	886	886	886	886	886	886	886
Deletions	0	0	0	0	0	403	403
IFFCO Kalol						113	113
GSFC						60	60
NFL, Vijaypur						93	93
KRIBHCO Hazira						137	137

The total naphtha demand for the country and for the Western region is as follows-

Table 16.2.8 Naphtha demand (excluding imports) (TMT)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Total	**8009**	**8104**	**7756**	**7915**	**6552**	**5777**

Table 16.2.9 Naphtha demand from Western sector (excluding imports) (TMT)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Western Region	3761	3827	3450	3703	3028	3109

Supply projections

The current refinery capacity in India is 114 MMTPA. Tenth plan working group on Refining has outlined a number of capacity additions in the tenth plan totalling to 106 MMTPA. This seems a bit ambitious and we have accordingly scaled down the capacity addition to about 56 MMTPA based on press reports on the progress made by refineries on their capacity addition plans. The table given below shows the comparison between our estimates and tenth plan estimates for capacity addition.

Table 16.2.10 Expected capacity additions in tenth plan

		Expected date of commissioning	
Refinery	Capacity addition	Xth Plan sub-group	Our estimates
IOC, Barauni	1.8	2002/3	2002/3
IOC, Haldia	1.4	2002/3	2002/3
HPCL, Mumbai	0.33	2002/3	2002/3
CPCL, Nagapatinam	0.5	2002/3	2002/3
RPL, Jamnagar	6	2002/3	2003/4
Essar, Jamnagar	10.5	2002/3	Uncertain
IOC, Koyali	4.3	2003/4	Uncertain
IOC, Panipat	6	2003/4	Uncertain
BPCL, Mumbai	5.1	2003/4	2004/5
CPCL, Chennai	3	2003/4	2004/5
BRPL, Bongaigaon	0.35	2003/4	2003/4
IOC, Paradip	9	2003/4	2006/7
Essar, Jamnagar	1.5	2003/4	Uncertain

Refinery	Capacity addition	Expected date of commissioning	
		Xth Plan sub-group	Our estimates
NOCL, Cuddalore	6	2003/4	Uncertain
KRL, Kochi	6	2004/5	2008/9
RPL, Jamnagar	17	2005/6	2006/7
Essar, Jamnagar	12	2005/6	Uncertain
HPCL, Bhatinda	9	2005/6	2005/6
BRPL, Bongaigaon	0 3	2006/7	2006/7
BORL, Bina	6	2006/7	Uncertain
Total	106.08		

In the western region, the only capacity addition that has been taken is the BPCL Mumbai refinery's 5.1 MMTPA addition. In this region, Reliance is also expected to expand its refinery but since it is more likely to export its naphtha production, it has been excluded from the analysis.

Applying the 95% capacity utilisation factor and refinery wise naphtha yields, which are around 10%, we have the following naphtha production forecast. This forecast excludes Reliance's production in the Western region as Reliance is assumed to export all its naphtha production.

Table 16.2.11 Naphtha production forecast (TMT)

	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07
Production	9355	9598	9453	10291	10273	10775

For the western region, the supply projections are as follows-

Table 16.2.12 Naphtha production forecast for Western region (TMT)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Western Region	4248	4258	4066	4600	4582	4571

Naphtha demand supply gap

Taking into account the projected naphtha demand (without imports, Table 1.5) and supply, we have the following all-India projected demand supply situation.

Table 16.2.13 Naphtha demand supply gap (TMT)

	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07
Demand	8009	8104	7756	7915	6552	5777
Supply	9355	9598	9453	10291	10273	10775
Gap	1346	1494	1697	2376	3721	4998

As this table shows, there is a projected surplus in naphtha in the country of as much as 4.9 million tonnes in the year 2006/7.

The following table shows the region wise demand supply situation.

Table 16.2.14 Regional Naphtha demand supply gap (TMT)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Western Region	487	431	616	897	1554	1462
Northern Region	-674	-677	-681	-685	31	1047
Eastern Region	729	834	857	832	805	1264
Southern Region	803	907	905	1333	1331	1225
Total	**1346**	**1494**	**1697**	**2376**	**3721**	**4998**

As against the projected naphtha surplus after 2002/3, the ONGC's production in this region is as follows.

Table 16.2.15 Projected ONGC's production (TMT)

Location	Product	2002-03	2003-04	2004-05	2005-06	2006-07
URAN	Naphtha/NGL	234	243	232	220	212
Hazira	ARN	1182	739	653	654	656
	Light Naphtha	0	244	244	244	244
Ankleshwar	NGL	9	8	7	6	5
Gandhar	Naphtha	31	29	27	21	17
TOTAL		1482	1290	1189	1171	1160

Source. ONGC

It can be concluded that given the surplus situation in naphtha of about 4.4 million tonnes in the year 2006/7, ONGC's production of about 1.1 million tonnes is likely to face a tough competition from other major players in this market.

Annexure - 16.3
Calculation of landed cost of LNG at various crude prices

Table 16.3.1 Ex-Hazira price of LNG at various crude prices

Elements	*Units*				
Crude Price	$/bbl	18	22	25	28
FOB LNG	$/MMBtu	2.65	3 25	3.70	4.15
Transportation	$/MMBtu	0.35	0 35	0.35	0.35
CIF	$/MMBtu	3.00	3.60	4.05	4.50
Customs duty	$/MMBtu	0.15	0 18	0.20	0.23
SADD	$/MMBtu	0.13	0.15	0.17	0.19
Landed Cost	$/MMBtu	3.28	3.93	4.42	4.91
Re-Gassification	$/MMBtu	0.40	0.40	0.40	0.40
Ex-Hazira	$/MMBtu	3.68	4.33	4.82	5.31

Imputed value calculations
Methodology

The imputed value of gas is the price of gas at which the cost of generation or production in a gas based plant equals the cost of generation/production using an alternative fuel, at a particular location. Thus it indicates the maximum price for gas at which it is competitive with the cheapest alternative fuel. The methodology used has been illustrated below.

Table 16.3.2 Methodology for calculating imputed value of gas

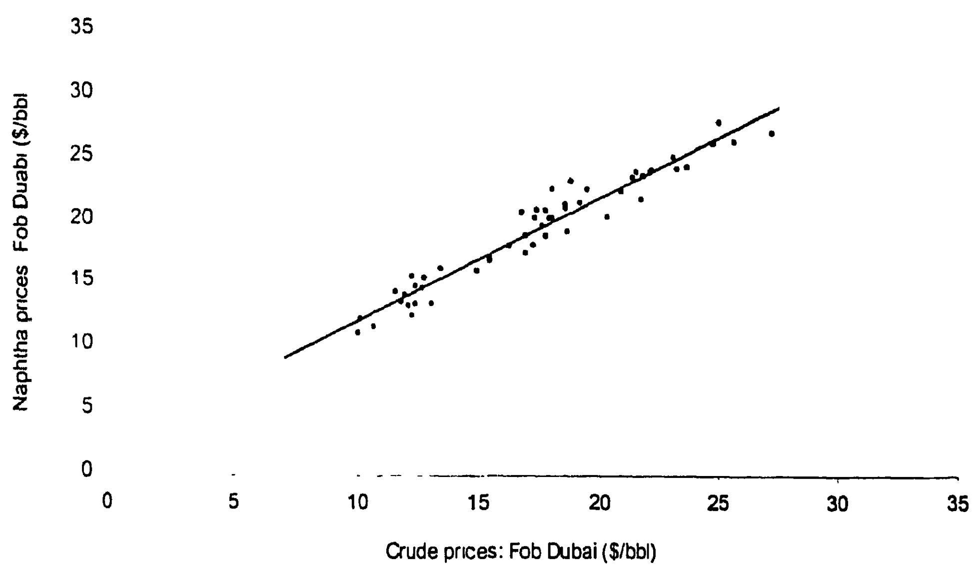
Cost of generation/production	Gas based	Competing technology
Capital cost	A	c
Operation and maintenance cost	B	d
Fuel cost	X (unknown)	e
Total cost		f = c + d + e
Imputed value of gas		X = f - a - b

Table16.3. 3 Model detailed imputed value calculation for fertiliser plant

Element	Unit	Gas	Naphtha (1)
Urea Capacity	Tons/Year	726000	726000
Capital Cost	Rs Million	17000	17500
Phasing of investment			
Year-2		0.2	0.2
Year-1		0.5	0.5
Year-0		0.3	0.3
Total		1	1
Discount factor		0.12	0.12
NPV factor		1.18	1.18
Capital cost (incld IDC)	Rs.million	19986	20574
Life of plant	Years	15	15
CRF		0.15	0.15
Annutised capital cost	Rs.million	2934	3021
Capital cost/Ton of urea	Rs./Ton	4042	4161
Fuel calorific value	kcal/NM^3, kcal/kg	8500	10560
Energy required per ton of urea	Gcal/Ton	5.40	5.10
Fuel consumption/Ton of Urea	NM^3, kg/Ton	635	483
Fuel cost	**Rs/t**		**8450**
Fuel cost/Ton of urea	Rs/Ton		4081
Fixed operating cost	Rs/Ton	854	924
Capital+Fixed O&M cost/Ton of Urea	Rs/Ton	4896	5085
Total cost per ton of urea	Rs/Ton		9166
Total cost per ton of urea	$/Ton		199
Imputed fuel charge	**Rs/Ton**		**4270**
Imputed fuel charge	**$/Ton**		**93**
Imputed value for gas	**$/MMBtu**		**4.33**

Annexure 16.4
Regression of naphtha prices with crude FOB AG

Figure 16.4.1

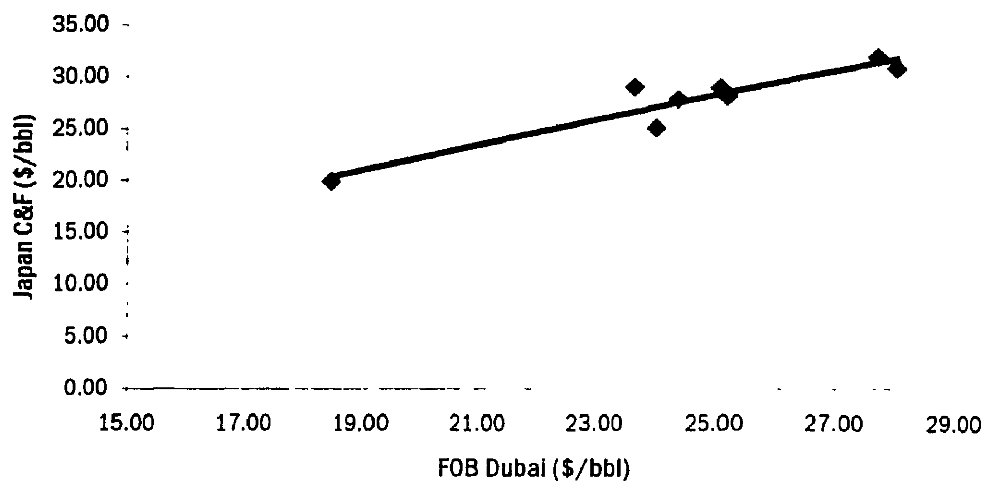


The regression equation works out to be

Naphtha price = 0.914 * (Dubai price) – 2.3009

Annexure 16.5
Regression of Japan C&F with crude FOB AG

Figure 16.5.1



The regression equation is estimated to be

Japan C&F = 1.1883 *(FOB crude) – 1.6692

Annexure 16.6
Detailed consumer profile in the Western region

Table 16.6.1 Consumer wise naphtha sales for fertiliser sector (TMT)

Supplier	Plant	Mar'01	Mar'00	2000/01	1999/00
IOC (M)	GNFC Bharuch	0	0	0	0.1
IOC (M)	GSFC Baroda	7.6	1.2	60.5	58.7
IOC (M)	Hindustan Nitro	0	0	0	0
IOC (M)	IFFCO Kalol	2.4	4.3	112.9	115.7
IOC (M)	NFL Vijaypur	4.5	0	93	74.9
IOC (M)	ZAC Goa	4.1	16	195.7	242.6
BPC	Deepak Fertilizer	1.1	0.3	12.2	12.1
BPC	GSFC	0	0	5.4	0
HPC	Deepak Fertilizer	0	0	0	0.9
HPC	KRIBHCO Hazira	12.2	5.6	136.5	142.7
HPC	RCF Thal	26.4	34.1	269.6	310.4
Total		**58.3**	**61.5**	**885.8**	**958.1**

Source. Industrial Performance Review, 2001.

Table 16.6.2 Consumer wise naphtha sales for Petrochemical sector (TMT)

Supplier	Plant	Mar'01	Mar'00	2000/01	1999/00
IOC (M)	Indus Easter	0	0	0	0
IOC (M)	IPCL Baroda	0	0	0	0
IOC (M)	IPCL Baroda	57.2	48.7	550.5	512
IOC (M)	Nirma Limited	0.4	0.2	2.1	0.6
IOC (M)	RIL Hazira	0	16.4	4.9	77.2
IOC (M)	RIL Jamnagar	0	24.5	71.2	102.9
IOC (M)	RIL Patalganga	0	9	10.9	33.4
IOC (M)	RPL Jamnagar	0	0	0	0
BPC	HOC Rosayani	0.5	0.7	3.4	5.5
BPC	National Peroxide	0.3	0.3	4.9	4.2
BPC	NOCIL Mumbai	25	26.3	255.4	186.4
BPC	Oriental Containers	0.9	1	9.1	5.4
BPC	Rama Petrochem	0	0	0	5.7
BPC	Reliance Industries	20.1	26	273.4	272.7
HPC	HOC	0	0	0	1.6
HPC	Oswal Agro	0	0	0	0
HPC	RIL Hazira	0	0	0	0.5
Total		**104.4**	**153.1**	**1185.8**	**1208.1**

Source. Industrial Performance Review, 2001.

Table 16.6.3 Consumer wise naphtha sales in power/steel sector (TMT)

Supplier	Plant	Mar'01	Mar'00	2000/01	1999/00
IOC (M)	Arvind Mills	0	0	0	6.6
IOC (M)	Birla Copper	0	0	0.7	5.8
IOC (M)	Dabhol Power	37.8	0	77.1	0.1
IOC (M)	Essar Power	0	0	38.9	232.4
IOC (M)	Essar Steel	0	42.6	126.1	278.7
IOC (M)	GACL	5.7	7.7	72.4	79
IOC (M)	GIPCL	1.2	14.4	67.9	146.1

Supplier	Plant	Mar'01	Mar'00	2000/01	1999/00
IOC (M)	GPEC (Nap)	0	35.8	214.7	296.9
IOC (M)	IPCL Dahej	22	29.4	281.5	186.2
IOC (M)	L&T Rajoula	5.9	5.4	61.8	51.8
IOC (M)	NTPC Hazira	0	0	0	0.5
IOC (M)	RSPL Goa	0	6.1	51.1	51.4
IOC (M)	Search Chem	3	0.3	19.9	41.3
BPC	Arvind Mills	3	3.6	55.2	41.5
BPC	Enron	0	0	0	8.2
BPC	Gujarat Alkali	4.9	3.6	56.7	50.5
BPC	Herdillia Chemicals	0.4	0.7	7.4	9.2
BPC	Search Chem	1.7	0	6.6	0
BPC	Vikram Ispat	0	2.7	7.6	20.9
HPC	Arvind Mills	3.8	2.1	17.8	13.9
HPC	GACL	0	0	0	5.9
HPC	Herdillia Chemicals	0	0	0.1	0
HPC	NTPC Kawas	48.2	5.9	369.2	126.9
HPC	Raymond Steel	0.4	0.2	2.8	3.6
HPC	Vikram Ispat	0	0	0	1
HPC	RSPL Goa	3.3	0	9.6	0
Total		141.3	160.5	1545.1	1658.4

Source. Industrial Performance Review, 2001.

Table 16.6.4 Consumer wise naphtha sales in Processor sector (TMT)

Supplier	Plant	Mar'01	Mar'00	2000/01	1999/00
IOC (M)	Aditya Petro	0	0.8	2.8	9.4
IOC (M)	Amit Petro	0	0.1	0	0.1
IOC (M)	Atlas Petrochem	0	0	0	4.9
IOC (M)	Avani Petro	0	0	0	15.2
IOC (M)	Bee Am Chem	0	2.7	18.5	32
IOC (M)	Bharat Petrochem	0	0	0	0.2
IOC (M)	Deepak Petro	0	0	0	0.5
IOC (M)	Gajanan Labs	0	0	3.4	0.2
IOC (M)	Gandhar Oil	0	0.9	0.9	7.4
IOC (M)	Govardhan Petro	0	0	0	11.4
IOC (M)	Hasndrup Petro	0	0	0	1.8
IOC (M)	Heera Petro	0	0.7	2.8	1.1
IOC (M)	JK Petrochem	0	0.1	2.6	0.1
IOC (M)	Jal-Hi Power Petro	0	0	0	6.9
IOC (M)	Parasnath Petro	0	1	2.5	7.2
IOC (M)	Patel Petrochem	0	0	0	7.7
IOC (M)	Poly Petro	0	0	5	0
IOC (M)	Ram remedies	0	4.7	11.6	28.8
IOC (M)	Rishi petrochem	0	0	0	4.7
IOC (M)	Silver Chem	0	1	3.5	11
IOC (M)	Sri Venkarteshwara	0	1	2.6	6.8
IOC (M)	Sulakhi Chemcials	0	2.3	5.9	15
IOC (M)	Suncoats & Chem	0	0.4	4.2	10.1
IOC (M)	Vamitiwala	0	0	1	0.1
IOC (M)	Venkatesh	0	0	0	5.8
IOC (M)	Yash Organics	0	0	0	5.6
IOC (M)	Others (WR)	0	0	1.2	0.1
BPC	Ankini Petro	0	0	0	7.2
BPC	Shrirang Petro	0	0.8	1.8	3.4
BPC	Others (WR)	3	1.4	9	5.7

HPC	Anant & Co	0	0.5	1.1	3.4
HPC	R S Petrochem	0	0.3	0	14
IBP	M P Petrochem	0	0	0	0.3
IBP	Maruti Petrochem	0	0	0	0.2
IBP	Panjwani Petro	0	0	0	0.3
IBP	Paschim Petro	0	0	0	13.7
IBP	Poly Petrochem	0	0	0	0.5
IBP	Shayona Petro	0	0	0	0.2
IBP	Thana Polyorganic	0	0	0	0.2
IBP	Vardan Chemicals	0	0	0.1	0.3
Total		**3**	**18.7**	**80.5**	**243.5**

Source. Industrial Performance Review, 2001.

Annexures
Part - 4
Risk Management
Issues

Annexure 17.1
Views of financial intermediaries

Given below are the views of two prominent financial intermediaries involved in hedging markets – Global Commodities and Citibank.

GLOBAL COMMODITIES

1. Major issues are diverse but particularly centre on risk/return of the organisation's mix of equity, asset plans, revenue profile and consequential risk profile, as well as the market outlook. Many state-controlled entities do use these markets but faster commercial decisions can be more difficult to make in public sector environments so they tend to be more cautious.
2. The larger and stronger the company the more it can argue that risk management is a matter of asset and cost management with sufficient equity to absorb the nasty cyclical flows that oil prices routinely seem to provide. However, even if there is a net overall cost to hedging because of paying premiums, or imperfect timing or implied credit and transaction costs, that does not negate the purpose of hedging. For there is a cost also of not hedging. Firstly by reserving cash and other resources and raising project hurdles to ensure viability through the cycle there is a considerable cost – less assets, declined project, spare balance sheet. Oil price payoffs are also asymmetrical – the pain of low prices and ultimately failure for commercial entities can be considerably more severe in impact than the marginal positive gain of still higher boom prices.
3. Exxon most famously used not to hedge at all arguing it too big and possibly feared anti trust issues. Other big oil companies use the markets but more to manage spreads – between crude and refining margins and in conjunction with physical trading. For ONGC however, the decision should turn more on its own circumstances. For example, is a foreign asset investment better left to the mercy of market prices or should reasonable return on capital be hedged to ensure the success of the decision. Should a marginal oil field be left undeveloped or speculatively developed in hope of picking the right part of the cycle – or underwritten with a hedge when the forward markets allow this. These are asset specific examples. Whether ONGC should hedge its routine cash flows might be more a function of how severely its investment and development plans would be at risk to lower prices.
4. The simplest solution would be for ONGC to sell its crude on a "netback" basis – that is instead of being paid a floating oil price like average of Brent

and Dubai, it might accept a product or product basket related price reflecting the yield of its crude oil to refiners. However, this simply transfers the refiner's problem to the producer – perhaps attractive as enticement to sell a new stream of crude or if there is sufficient premium being paid. ONGC might also consider selling fixed price physical to the refiners who would then hedge sell the resultant products, assuming they export enough to be allowed to do so. Derivative solutions are superior and would typically be separate – the producer hedging at its preferred timing, pricing and structure and the refiner the same – both accessing the more liquid international markets. Possibly they could hedge simultaneously to create a net product hedge sale, but only if the producer's crude hedge target's occurrence happened to coincide with the refiner's crack target.

5. The latest fashion is increasingly for exchanges and over-the-counter (OTC) markets to converge for example as NYMEX seeks to build out its futures based electronic exchange and electronic Intercontinental Exchange (ICE) looks to incorporate its recently acquired IPE futures exchange in London. Classically, however, ONGC would be well advised to look at both types of markets, perhaps even dabble in both but I guess it would be more likely to gravitate towards the OTC markets. This is because they offer superior basis risk, longer maturities and more varied option structures often with no or less margining and more convenient execution and settlement. Futures are however excellent tools for shorter dated trading and speculating. There are no relevant futures in Asia – Simex tried a Dubai contract unsuccessfully and NYMEX's recent attempt has disappeared. E&P companies round the world are frequent users of OTC hedge markets in oil and gas.
6. I would suggest ONGC concentrate on swaps and floors perhaps zero cost collars and participating floors. It might consider some pilot hedges using a few different instruments to test the waters and increase internal understanding and confidence. Initially it might use hedges basis the average of the Brent futures or basis Dated Brent and possibly some Dubai hedges.
7. A hedge programme may typically look something like 10-15% of year one production, 5-35% of year two and 0-20% of year three and beyond with separate approvals to hedge quite far if warranted e.g. 5-7 years for new projects, acquisitions and investments.
8. It might not be initial focus of hedging especially since as Naphtha is not particularly liquid market. However, Kerosene in particular has attractive contango for winter months which ONGC may exploit. Also as a soft entrée into hedging it might be worth considering spread trade bringing some of

this production back to a crude price basis – arguably ONGC's natural position. Also any regulatory advantages might be helpful – for example if these products are exported so that only they can be hedged under current rules.

9. It might be useful to consider procedures you have already for other markets like FX and interest rates and also for other decisions. Clearly, a board authority and plan approval is required. Most likely below that would be a committee perhaps including senior finance and market people. Then below that would be delegated execution authorities to senior traders and traders – again either treasury or marketing department people. A reasonable high degree of delegated authority is useful though initially difficult to obtain. Certainly at execution the procedures must be mindful that these are potentially fast moving markets requiring instant decisions. ONGC should have ideally separate back office function so the trader does not confirm or settle his own trades. Obviously, there needs to be a system in background and accounting tax and other implications and procedures need to be considered. The senior officials, committee and ultimately the board might review regular trading and position. Once the regulatory environment clears, ONGC should move rapidly towards executing an ISDA Master document – this is a master agreement that would govern future hedging and should be in place, however, executing the master entails no commitments, merely a preparedness.

CITIBANK

1. There are a number of examples of national oil companies hedging the price risk in South America and Africa. It is less prevalent in the G 7 countries as oil companies are not government owned.
2. There are three primary reasons as to why the mean reversion tendency of crude prices should not play a roll in ONGC's decision to hedge or not hedge.
   a) Cost of capital – The simplest example is that a company can have -$5 in revenues this year and +$15 in revenues in the next year. On average, revenues over the two year period would be $7.5. However, the impact of the -$5 in revenues in year 1 could range anywhere from insolvency to significant over borrowing at high cost to fund such a shortfall in revenues. Thus, mean reverting tendency gives all the more reason to hedge and smooth earnings and cash flows.
   b) Measurement of financial performance – In light of the fact that this is measured on a quarterly and annual basis, it is in the mutual interest of both management and the shareholders to mitigate for such fluctuations.
   c) Public sector use of funds – ONGC's mission is as much preservation of public funds as it is the capturing the upside in an environment in which crude price rally. In other words, if we evaluate any investment by ONGC in the same framework as we would for any other public sector project, the concern would not focus in price volatility but stable growth achieved through the combination of increasing production, strong cost controls and stable/smooth flow of revenues.
   d) Mean Reversion Cycle – While it is true that crude oil does show strong mean reversion characteristics and that on average the cycle is about 5 years, it is also important to note that the duration of such cycles will vary. That is one cycle may last three years while the another one last 5 years. Depending on such moving targets which the long make the capital budgeting and investment processes much more difficult. As investment is critical to growth which in turn is critical for assuring appropriate return on public funds, this mean reverting tendency gives all the more reason for ONGC to hedge.
   e) Volatility – Inherent volatility in oil prices, which ultimately results in this mean reverting characteristics, creates a tremendous amount of trading value to marginal traders in the crude oil market. This value can be actualised by ONGC through implementation of hedging strategies using options. In effect ONGC carries value in its asset base which it can

monatize. While this is a more advanced stage of hedging, in principle, it suggests that volatility should be a reason to hedge rather than a cause to shy away from it.

3. Unless you believe that the price of oil is on an infinite upward price trajectory, there cannot, in the crude oil market, be a situation where shareholder value is infinitely enhanced. That is, while it is true that the share price of an unhedged producer will appreciate faster than that of a hedge producer during times when crude prices rally, by definition, they must depreciate faster as crude prices revert back to their historic mean. Therefore, unhedged companies generally experience greater share price volatility. In the long run, it is unclear whether increased share price enhances shareholder value.
4. It may be more efficient for ONGC to bypass the market place and therefore save costs associated with hedging through a market maker/liquidity provider. A number of market participants have taken this view in the past, however, the theory proves more difficult than practice. That is in fact the reason that market makers exist. The ultimate stumbling block that corporate have found in attempting to bypass the market makers is that they must significantly compromise their hedge objectives in order to come to some sort of an agreement.
5. The major E&P companies use a mix of OTC and exchange traded instruments. These two may rather be viewed as complements. General use of exchange traded instruments is confined to short term tenors, that is less then six months and to futures as opposed to apportions due to lack of liquidity. The OTC market evolved to address specific concerns that E&P companies have had with futures exchanges, namely –
   - inability to execute large value, long term tenors
   - margin settlement concerns
   - lack of customized hedges design

   Traditional use of futures exchanges by E&P companies' focuses on short term price management associated with ongoing shipments and stored barrels. A primary potential concern for ONGC is the fact that its geographic location makes it more reliant on less liquid grades making the liquid exchange contracts, WTI or Brent, potentially not as effective.
6. There are endless varieties possible in hedging instruments in the OTC market, ranging from a simple swap to complex options. That is in fact one of the advantages that ONGC has by tapping into the OTC market. In other

words, companies of a lesser credit quality must confine themselves to exchange traded instruments as they are required to post margin collateral on a daily basis. The choice of OTC instruments ultimately depends upon the view of the market that the company takes the risk management strategy and a cash management strategy. The use of such instruments is a benefit that ONGC can derive as a function of its credit and balance sheet quality as such would in fact reflects heightened credit appetite by multinational financial instruments. Ultimately, use of such instruments is a result of an iterative process. The purpose of this process would be to develop a clear understanding of the mechanics of such structures by beginning is simple swaps and options and moving on to more structured products.

7. The determination of optimal tenor for price risk is a function of hedging objective, price targets and risk appetite. Ultimately, a risk policy framework must be established and determination of tenor would be outlined. The traditional approach applied by large E&P companies is to reduce the relative position of hedges as one moves further out in time. Therefore, the traditional hedge profile would be something like:
   50-75% hedged for 1 year
   25-50% hedged from 2 to 5 years
   less than 25% hedged beyond 5 years
8. Assuming that a hedge policy's primary objective is to smooth cashflows, a mixture of product hedges would be prudent regardless of specific quantity relative to total production. The primary issue of concern ought to be liquidity. That is, lack of liquidity may make the hedge unattractive as lack of liquidity will be reflected in pricing level.
9. The approval structure is again to be formalised in the risk policy. It is suggested that limits be put in place for each authority level, beyond which higher authority should be involved in the pre-transaction stage. Also, post-transaction, the MTM of the portfolio should be tracked periodically and loss limits defined.

Annexure 17.2

Spot deals for Asian and Australian crude oils by country 1986-1995

	1986	1987	1988	1989	1990	1991	1992	1993	1994	19
Indonesia	196	203	125	132	120	176	163	184	263	2
Malaysia	73	60	102	127	59	85	86	88	81	
Australia	17	25	28	38	19	27	34	23	25	
PNG							22	47	30	
Vietnam		1				1		2	6	
China	5	1	6	2		9	10	6	3	
Others	6	1		2		5	8	3	1	
TOTAL	297	291	261	301	198	303	323	353	409	3

Source. "Oil in Asia", Oxford University Press

Annexure 17.3

Reported spot deals for Asian and Australian crude oils by grade 1986-95

	1986	1987	1988	1989	1990	1991	1992	1993	1994
Indonesia									
Minas	22	45	43	43	47	66	67	70	107
Belida							1	11	16
Duri	15	21	14	28	23	22	20	44	56
Widuri						38	29	37	42
Cinta	31	29	12	8	14	1	13	3	11
Attaka	27	18	12	9	3	15		1	7
Bontang Mix									1
Ardjuna	5	3	3	6	5	5	3	2	8
Kerapu									
Lalang	10	11	11	11	5	1	6	2	2
Bekapai	6	6	1	4	2	6	5	1	2
Arun Condensate	43	25	15	5	2	1			2
Bima		13	5	5	1	2	3		
Walio	19	6	3	1					2
Kakap	3	12	4	4	15	13	2	1	1
Handil	7	1		1		4	4	5	
Badak		1					3	6	5
Udang	4	6	1	3					
Others	4	6	1	4	3	2	7	1	1
Malaysia									
Tapis	51	32	68	75	33	58	72	78	58
Labuan	18	24	23	41	18	13	11	10	16
Dulang						11	3		3
Miri	3	2	8	10	7	2			4
Bintulu	1	2	3	1	1	1			
Australia									
Saladin	0	0	0	0	4	9	10	5	7
Cossack	0	0	0	0	0	0	0	0	0
NW Shelf Condensate	0	0	0	1	0	2	0	0	1
Griffin	0	0	0	0	0	0	0	1	10
Gippsland	14	20	17	5	1	5	5	7	0
Jabiru	2	5	9	14	6	4	7	2	0
Skua	0	0	0	0	0	0	7	3	3
Talisman	0	0	0	9	2	0	1	0	0
Challis	0	0	0	1	4	5	1	1	0
Others	1	0	2	8	2	2	3	4	4
Papua New Guinea									
Kutubu							22	47	30
TOTAL	286	288	255	297	198	288	305	342	399

Source. "Oil in Asia" Oxford University Press